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TAMPA ELECTRIC
A TECO ENERGY COMPANY

RECEIVED
JUL 05 1994
Department of Environmental Protection
SOUTHWEST DISTRICT
BY ________

June 30, 1994

Richard Garrity, Ph.D.
Florida Department
of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

Hand Delivered

A029-254[illegible]

Re: Tampa Electric Company
Big Bend Station-Unit 3 Air Permit Amendment Request
AO29-179911

Dear Dr. Garrity:

As you are aware, recent legislation involving nitrogen oxide compliance limits has been signed by the Governor and becomes effective July 1, 1994. This law requires those emission units which install continuous emission monitors as a requirement of 40 C.F.R. Part 75 (Acid Rain Regulations) to demonstrate compliance with existing state imposed nitrogen oxides limits based on a 30-day rolling average. Big Bend Unit 3 is a source affected under this law.

The legislation does not specify the methodology for calculating the 30-day rolling average. Therefore, TEC proposes to calculate the 30-day rolling average for Unit 3 using the same methodology employed in Big Bend Unit 4. This methodology uses the criteria set forth in 40 C.F.R. Part 60, Subpart Da and is computed using the equations set forth in 40 C.F.R. Part 60, Appendix A, Reference Method 19, Section 4.2 (Attachment 1). All valid data collected during boiler operating days will be used to calculate the 30-day rolling average except during periods of start-up, shutdown, or malfunction. Quality assurance of the continuous emissions monitor shall be done in accordance with requirements contained in 40 CFR Part 75.

On July 1, 1994, TEC will begin collection of CEM data for 30 boiler operating days of valid hourly data. This data will be used to demonstrate compliance with the NO_x limit using a 30-day rolling average. TEC will submit quarterly NO_x CEM reports showing the 30-day rolling average and other pertinent information (ie. time of start-up, shut-down, etc.). Compliance with the NO_x limit for Unit 3 using the 30-day rolling average will eliminate the need to do stack testing for NO_x. For your information, the current Unit 3 compliance test window is from May 17 through August 14.

TEC has attached suggested wording (Attachment 2) for the permit's specific conditions that are affected by this new legislation for your use in amending the permit.

Dr. Richard Garrity
June 30, 1994
Page 2

TEC feels the above methodology is consistent and efficient, and requests that the Florida Department of Environmental Protection amend the Big Bend Unit 3 permit accordingly. Your expedient review and approval in this amendment request is appreciated.

Please feel free to call Ms. Janice Taylor or me at (813) 228-4839 should you have further questions in this matter. Thank-you.

Sincerely,

Patrick A. Ho, P.E.
Manager
Environmental Planning

/QQ648

Attachments

c/att: Bill Thomas, FDEP, Tampa
Clair Fancy, FDEP, Tallahassee
Jerry Campbell, EPCHC

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ATTACHMENT 1

TABLE 19-1—FFACTORS FOR VARIOUS FUELS[1]

Fuel type	F_d		F_w		F_c	
	dscm/J	dscf/10^6 Btu	wscm/J	wscf/10^6 Btu	scm/J	scf/10^6 Btu
Coal:						
Anthracite[2]	2.71×10^{-7}	10,100	2.83×10^{-7}	10,540	0.530×10[illegible]	1,970
Bituminous[2]	2.63×10^{-7}	9,780	2.86×10^{-7}	10,640	[illegible]$.484$[illegible]	1,800
Lignite	2.65×10^{-7}	9,860	3.21×10^{-7}	11,950	0.513[illegible]	1,910
Oil[3]	2.47×10^{-7}	9,190	2.77×10^{-7}	10,320	0.383[illegible]	1,420
Gas:						
Natural	2.43×10^{-7}	8,710	2.85×10^{-7}	10,610	[illegible]$.287$[illegible]	1,040
Propane	2.34×10^{-7}	8,710	2.74×10^{-7}	10,200	[illegible]$.321$[illegible]	1,190
Butane	2.34×10^{-7}	8,710	2.79×10^{-7}	10,390	[illegible]$.337$[illegible]	1,250
Wood	2.48×10^{-7}	9,240	....	....	[illegible]$.492\times10$[illegible]	1,830
Wood Bark	2.58×10^{-7}	9,600	....	....	0.516×10[illegible]	1,920
Municipal	2.57×10^{-7}	9,570	....	....	0.488×10[illegible]	1,820
Solid Waste	....					

[1] Determined at standard conditions: 20 °C (68 °F) and 760 mm Hg (29.92 in. Hg).
[2] As classified according to ASTM D388-77.
[3] Crude, residual, or distillate.

3.2 Determined F Factors. If the fuel burned is not listed in Table 19-1 or if the owner or operator chooses to determine an F factor rather than use the values in Table 19-1, use the procedure below:

3.2.1 Equations. Use the equations below, as appropriate, to compute the F factors:

$$F_d = K[(K_{hd}\%H) + (K_c\%C) + (K_s\%S) + (K_n\%N) - (K_o\%O)]/GCV \qquad \text{Eq. 19-13}$$

$$F_w = K\{(K_{hw}\%H) + (K_c\%C) + (K_s\%S) + (K_n\%N) - (K_o\%O) + (K_w\%H_2O)]/GCV_w \qquad \text{Eq. 19-14}$$

$$F_c = K(K_{cc}\%C)/GCV \qquad \text{Eq. 19-15}$$

(NOTE.—*Omit the %H_2O term in the equations for F_w if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.*)

where:

F_d, F_w, F_c=volumes of combustion components per unit of heat content, scm/J (scf/million Btu).

%H, %C, %S, %N, %O, and %H_2O=concentrations of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of fuel, weight percent.

GCV=gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).

K=conversion factor, 10^{-5} (kJ/J)/(%) [10^6 Btu/million Btu].

K_{hd}=22.7 (scm/kg))[(3.64 (scf/lb)/(%)].

K_c=9.57 (scm/kg)[(1.53 (scf/lb)/(%)].

K_s=3.54 (scm/kg) [(0.57 (scf/lb)/(%)].

K_n=0.86 (scm/kg [0.14 (scf/lb)/(%)].

K_o=2.85 (scm/kg) [0.46 (scf/lb)/(%)].

K_{hw}=34.74(scm/kg)[(5.57 (scf/lb)/(%)].

K_w=1.30 (scm/kg) [(0.21 (scf/lb)/(%)].

K_{cc}=2.0 (scm/kg) [(0.321 (scf/lb)/(%)].

3.2.2 Use applicable sampling procedures in Section 5.2.1 or 5.2.2 to obtain samples for analyses.

3.2.3 Use ASTM D3176-74 (incorporated by reference—see §60.17) for ultimate analysis of the fuel.

3.2.4 Use applicable methods in Section 5.2.1 or 5.2.2 to determine the heat content of solid or liquid fuels. For gaseous fuels, use ASTM D1826-77 (IBR—see §60.17) to determine the heat content.

3.3 F Factors for Combination of Fuels. If combinations of fuels are burned, use the following equations, as applicable unless otherwise specified in applicable subpart:

$$F_d = \sum_{k=1}^{n} X_k F_{dk} \qquad \text{Eq. 19-16}$$

$$F_w = \sum_{k=1}^{n} X_k F_{wk} \qquad \text{Eq. 19-17}$$

$$F_c = \sum_{k=1}^{n} X_k F_{ck} \qquad \text{Eq. 19-18}$$

where:

X_k=*fraction of total h*[illegible]*nput* [illegible]*ach type of fuel k.*

n=number of fuels b[illegible]urn[illegible]ombination.

4. Determination of A[illegible]*rage P*[illegible]*nt Rates*

4.1 Average Pollu[illegible]nt R[illegible]rom Hourly Values. When [illegible]urly a[illegible] pollutant rates (E_h), inlet or outle[illegible] obtained (e.g., CEMS va[illegible]es), com[illegible] the average pollutant rate [illegible]$_a$) for th[illegible]rformance test period (e.g., 30 days[illegible]fied in the applicable regulation using [illegible] following equation:

$$E_a = (1/H) \sum_{[illegible]=1}^{n} E[illegible] \qquad \text{Eq. 19-19}$$

where:

E_a=average pollutant rat[illegible] for th[illegible]pecified performance test period [illegible]g/J (lb/million Btu).

E_h=hourly average pollutan[illegible]g/J (lb/million Btu).

H=total number o[illegible] operating [illegible] for which pollutant rates are deter[illegible]ed in the *performance test period.*

4.2 Average Pollutant Rates f[illegible] Other than Hourly Averages. When [illegible]tant rates are determined from meas[illegible] values *representing longer than 1-h*[illegible] periods (e.g., daily fuel sampling and [illegible]yses or Method 6B values), or when [illegible]tant rates are determined from com[illegible]ions of 1-hour and longer than 1-hou[illegible]iods (e.g., CEMS and Method *6B* [illegible]es), compute the average pollutant [illegible] (E_a) for the performance test period ([illegible] 30

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days) specified in the applicable regulation using the following equation:

$$E_a = \left[\sum_{j=1}^{D} (n_d E_d)_j \right] / \sum_{j=1}^{D} n_{dj}$$

Eq. 19-20

where:

E_a=average pollutant rate for each sampling period (e.g., 24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g., amount of fuel bunkered), ng/J (lb/million Btu).

n_d=number of operating hours of the affected facility within the performance test period for each E_d determined.

D=number of sampling periods during the performance test period.

4.3 Daily Geometric Average Pollutant Rates from Hourly Values. The geometric average pollutant rate (E_{ga}) is computed using the following equation:

$$E_{ga} = \mathrm{EXP} \left[(1/n) \sum_{j=1}^{n} [\ln(E_{hj})] \right]$$

Eq. 19-20a

where:

E_{ga}=daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent O_2.

E_{hj}=hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

n=total number of hourly averages for which pollutant rates are available within the 24 hr midnight to midnight daily period.

ln=natural log of indicated value.

EXP=the natural logarithmic base (2.718) raised to the value enclosed by brackets.

5. Determination of Overall Reduction in Potential Sulfur Dioxide Emission

5.1 Overall Percent Reduction. Compute the overall percent SO_2 reduction (%R_o) using the following equation:

$$\%R_o = 100 \left[1.0 - (1.0 - \%R_f/100)(1.0 - \%R_g/100) \right]$$

Eq. 19-2[illegible]

where:

%R_f=SO_2 removal efficiency from fuel pretreatment, percent.

%R_g=SO_2 removal efficiency of the control device, percent.

5.2 Pretreatment Removal Efficiency (Optional). Compute the SO_2 removal efficiency from fuel pretreatment (%R_f) for the averaging period (e.g., 90 days) as specified in the applicable regulation using the following equation:

$$\%R_f = 100 \left(1.0 - \left[\sum_{j=1}^{n} (\%S_{pj}/GCV_{pj})\, L_{pj} \right] / \left[\sum_{j=1}^{n} (\%S_{rj}/GCV_{rj})\, L_{rj} \right] \right)$$

Eq. 19-2[illegible]

where:

%S_p, %S_r=sulfur content of the product and raw fuel lots, respectively, dry basis weight percent.

GCV_p, GCV_r=gross calorific value for the product and raw fuel lots, respectively, dry basis, kg/kg (Btu/lb).

L_p, L_r=weight of the product and raw fuel lots, respectively, metric ton (ton).

n=number of fuel lots during the averaging period.

NOTE: In calculating %R_f, include %S and GCV values for all fuel lots that are not pretreated and are used during the averaging period.

5.2.1 Solid Fossil (Including Waste) Fuel—Sampling and Analysis.

NOTE: For the purposes of this method, raw fuel (coal or oil) is the fuel delivered to the desulfurization (pretreatment) facility. For oil, the input oil to the oil desulfurization process (e.g., hydrotreatment) is considered to be the raw fuel.

5.2.1.1 Sample Increment Collection. Use ASTM D2234-76 (IBR—see §60.17), Type I, Conditions A, B, or C, and systematic spacing. As used in this method, systematic spacing is intended to include evenly spaced increments in time or increments based on equal weights of coal passing the collection area.

As a minimum, determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D2234-76. Collect one gross sample for each lot of raw coal and one gross sample for each lot of product coal.

5.2.1.2 ASTM Lot Size. For the purpose of Section 5.2 (fuel pretreatment), the lot size of product coal is the weight of product coal from one type of raw coal. The lot size of raw coal is the weight of raw coal used to produce one lot of product coal. Typically, the lot size is the weight of coal processed in a 1-day (24-hour) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a steam generating unit may be used if representative sampling can be conducted for each raw coal and product coal.

NOTE: Alternative definitions of lot sizes may be used, subject to prior approval of the Administrator.

5.2.1.3 Gross Sample Analysis. Use ASTM D2013-72 to prepare the sample, ASTM D3177-75 or ASTM D4239-85 to determine sulfur content (%S), ASTM D3173-73 to determine moisture content, and ASTM D2015-77 or ASTM D3286-85 to determine gross calorific value (GCV) (all methods cited IBR—see §60.17) on a dry basis for each gross sample.

5.2.2 Liquid Fossil Fuel—Sampling and Analysis. See NOTE under Section 5.2.1.

5.2.2.1 Sample Collection. Follow the procedures for continuous sampling in ASTM D270-65 (Reapproved 1975) (IBR—see §60.17) for each gross sample from each fuel lot.

5.2.2.2 Lot Size. For the purpose of Section 5.2 (fuel pretreatment), the lot size of a product oil is the weight of product oil from one pretreatment facility and intended as one shipment (ship load, barge load, etc.). The lot size of raw oil is the weight of each crude liquid fuel type used to produce a lot of product oil.

NOTE: Alternative definitions of lot sizes may be used, subject to prior approval of the Administrator.

5.2.2.3 Sample Analysis. Use ASTM D129-64 (Reapproved 1978), ASTM D1552-83, or ASTM D4057-81 to determine the sulfur content (%S) and ASTM

[Part 60, Appendix A, Method 19]

ATTACHMENT 2 UNIT 3

Page 2 of 7 Specific Condition No. 5

From:

5. The nitrogen oxides emission rate (expressed as NO_2) from this source shall not exceed 0.70 pound per million Btu heat input. [Rule 17-2.600(5)(a)4.b, F.A.C.].

To:

5. **The nitrogen oxides emission rate (expressed as NO_2) from this source shall not exceed 0.70 pounds per million Btu heat input based upon a 30-day rolling average. [Rule 17.296.405(1)(d)4.,F.A.C.].**

Page 4 of 7 Specific Condition No. 10

From:

10. This source shall be stack tested for nitrogen oxides (expressed as NO_2) at intervals of 12 months from the date of August 14, 1989, or within a 90-day period prior to that annual date. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

To:

10. **This source shall demonstrate compliance for nitrogen oxides (expressed as NO_2) based upon a 30-day rolling average. The methodology to be used will follow the criteria set forth in 40 CFR Part 60, Subpart Da. The calculations shall be consistent with the equations in 40 CFR Part 60, Appendix A, Reference Method 19, Section 4.2. Data collected during boiler operating days will be used to calculate the 30-day rolling average except during periods of start-up, shutdown, or malfunction, consistent with the provisions of Rule 17-210.700, F.A.C.**

For the purpose of calculating a 30-day rolling average, a boiler operating day is defined as a 24-hour period (between 12.01 am and 12:00 midnight) during which fossil fuel is combusted in a steam operating unit for the entire 24-hours.

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The continuous emission monitor shall meet the quality assurance requirements and performance specifications contained in 40 CFR, Part 75.

A report shall be submitted to both the Florida Department of Environmental Protection and the Environmental Protection Commission of Hillsborough within 30 days following each calendar quarter. This report shall contain the 30-day rolling average, all time periods of boiler operation as well as a statement of CEM and/or boiler malfunction, start-up or shutdown.

/bb3scc

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Cindy
2.
3.
4.
5.

PLEASE PREPARE REPLY FOR:

- ____ SECRETARY'S SIGNATURE
- ____ DIV/DIST DIR SIGNATURE
- ____ MY SIGNATURE
- ____ YOUR SIGNATURE
- ____ DUE DATE ________

ACTION/DISPOSITION

- ____ DISCUSS WITH ME
- ____ COMMENTS/ADVISE
- ____ REVIEW AND RETURN
- ____ SET UP MEETING
- X FOR YOUR INFORMATION
- ____ HANDLE APPROPRIATELY
- ____ INITIAL AND FORWARD
- ____ SHARE WITH STAFF
- ____ FOR YOUR FILES

COMMENTS:

NO_x does not appear to be a problem if virgin #2 oil is used as a startup fuel at the Gannon station.

However, if #6 fuel is used at Big Bend, then NO_x could be a problem.

FROM: Lennon DATE: 1/1996 PHONE: ________

DEP 15-026 (12/93)

1.3 Fuel Oil Combustion

1.3.1 General[1-2, 26]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred ~~to as Bunker C.~~ Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Emissions[27]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

In this section, point source emissions of nitrogen oxides (NO_x), SO_2, PM, and carbon monoxide (CO) are being evaluated as criteria pollutants (those emissions for which National Primary and Secondary Ambient Air Quality Standards have been established. Particulate matter emissions are sometimes reported as total suspended particulate (TSP). More recent data generally quantify the portion of inhalable PM that is considered to be less than 10 micrometers in aerodynamic diameter (PM-10). In addition to the criteria pollutants, this section includes point source emissions of some noncriteria pollutants, nitrous oxide (N_2O), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs), as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of carbon dioxide (CO_2) are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO, much of which ultimately oxidizes to CO_2 or as carbon in the ash. Finally, fugitive emissions associated with the use of oil at the combustion source are being included in this section.

Tables 1.3-1, 1.3-2, 1.3-3, and 1.3-4 present emission factors for uncontrolled emissions of criteria pollutants from fuel oil combustion. A general discussion of emissions of criteria and noncriteria pollutants from coal combustion is given in the following paragraphs. Tables 1.3-5, 1.3-6, 1.3-7, and 1.3-8 present cumulative size distribution data and size-specific emission factors for

Table 1.3-1 (Metric Units). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e,f]		Filterable PM[g]	
	kg/10^3 L	EMISSION FACTOR RATING	kg/10^3 L	EMISSION FACTOR RATING	kg/10^3 L	EMISSION FACTOR RATING	kg/10^3 L	EMISSION FACTOR RATING	kg/10^3 L	EMISSION FACTOR RATING
Utility boilers										
No. 6 oil fired, normal firing (1-01-004-01)	19S	A	0.69S	C	8	A	0.6	A	—[h]	A
No. 6 oil fired, tangential firing (1-01-004-04)	19S	A	0.69S	C	5	A	0.6	A	—[h]	A
No. 5 oil fired, normal firing (1-01-004-05)	19S	A	0.69S	C	8	A	0.6	A	—[h]	B
No. 5 oil fired, tangential firing (1-01-004-06)	19S	A	0.69S	C	5	A	0.6	A	—[h]	B
No. 4 oil fired, normal firing (1-01-005-04)	18S	A	0.69S	C	8	A	0.6	A	—[h]	B
No. 4 oil fired, tangential firing (1-01-005-05)	18S	A	0.69S	C	5	A	0.6	A	—[h]	B
Industrial boilers										
No. 6 oil fired (1-02-004-01/02/03)	19S	A	0.24S	A	6.6	A	0.6	A	—[h]	A
No. 5 oil fired (1-02-004-04)	19S	A	0.24S	A	6.6	A	0.6	A	—[h]	B
Distillate oil fired (1-02-005-01/02/03)	17S	A	0.24S	A	2.4	A	0.6	A	—[h]	A
No. 4 oil fired (1-02-005-04)	18S	A	0.24S	A	2.4	A	0.6	A	—[h]	B
Commercial/institutional/residential combustors										
No. 6 oil fired (1-03-004-01/02/03)	19S	A	0.24S	A	6.6	A	0.6	A	—[h]	A
No. 5 oil fired (1-03-004-04)	19S	A	0.24S	A	6.6	A	0.6	A	—[h]	B
Distillate oil fired (1-03-005-01/02/03)	17S	A	0.24S	A	2.4	A	0.6	A	—[h]	A
No. 4 oil fired (1-03-005-04)	18S	A	0.24S	A	2.4	A	0.6	A	—[h]	B
Residential furnace (No SCC)	17S	A	0.24S	A	2.2	A	0.6	A	0.3	A

DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT SYSTEM

28-OCT-96 FACILITY EMISSION REPORT Page:1

AIRS ID: 0570039 # of Emissions Unit: 19
Owner: TECO
Name: BIG BEND STATION
City: RUSKIN Office: SWHI County: HILLSBOROUGH
Status: A Compliance Tracking Code: A DFC: 29-AUG-95
SIC: 4911 PSD: Y PPS: Y NSPS: Y NESHAP:
Title V Source: Y Syn Non-Title V Source: Small Business Stationary:
Major of HAPS: Y Major of Non-HAP Pollutants:
Syn Minor of HAPS: Syn Minor of Non-HAP Pollutants:

E.U. 1 Desc: UNIT #1 COAL FIRED BOILER W/RESEARCH-COTRELL ESP

Pollutant	Poten (TPY)	Allow (TPY)	1995 Actual (TPY)	1994 Actual (TPY)
VOC	56.0000		43.2500	34.0000
SO2	114936.0000	114936.0000	33311.0400	46862.0000
PM	1770.0000	1770.0000	1179.4000	720.0000
NOX	27029.0000		20992.7400	16607.0000
CO	477.0000		371.3900	294.0000
PM10			1179.4000	719.0000
PB			8.2100	6.0000

E.U. 2 Desc: UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP

Pollutant	Poten (TPY)	Allow (TPY)	1995 Actual (TPY)	1994 Actual (TPY)
VOC	56.0000		42.6400	33.0000
SO2	113766.0000	113766.0000	34223.0400	46717.0000
PM	1752.0000	1752.0000	1160.4000	456.0000
NOX	27118.0000		20696.7400	15871.0000
CO	477.0000		366.1900	282.0000
PM10			1160.4000	456.0000
PB			8.0900	6.0000

E.U. 3 Desc: UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP

Pollutant	Poten (TPY)	Allow (TPY)	1995 Actual (TPY)	1994 Actual (TPY)
VOC	58.0000		38.6400	41.0000
SO2	117156.0000	117156.0000	17132.0400	58404.0000
PM	1805.0000	1805.0000	646.9000	725.0000
NOX	12619.0000		8149.7400	9427.0000
CO	499.0000		332.1900	357.0000
PM10			646.9000	724.0000
PB			7.3400	8.0000

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten (TPY)	Allow (TPY)	1995 Actual (TPY)	1994 Actual (TPY)
PM10			59.5000	48.0000
PB			8.8800	10.0000

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
VOC	43.0000		46.8000	51.0000
SO2	15552.0000	15662.0000	2656.2400	6911.0000
PM	569.0000		59.5000	48.0000
NOX	11379.0000	11379.0000	7236.6200	6934.0000
CO	552.0000		401.2700	439.0000

E.U. 5 Desc: BIG BEND STATION COMBUST. TURBINE #2 - FIRED BY NO

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
VOC	162.0000		0.6000	0.0000
SO2	1213.0000	1375.0000	17.5600	5.0000
PM	145.0000	145.0000	0.6300	1.0000
NOX	1958.0000		8.5100	7.0000
CO	447.0000		1.9300	2.0000
PM10			0.6300	1.0000
PB			0.0000	

E.U. 6 Desc: GAS TURBINE #3 - WESTINGHOUSE TURBINE FIRED BY NO.

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
VOC	162.0000		1.0100	1.0000
SO2	1213.0000	1375.0000	29.6700	6.2700
PM	145.0000	145.0000	1.0600	0.0200
NOX	1958.0000	1960.0000	14.3700	9.2400
CO	445.0000	445.0000	3.2600	2.0000
PM10			1.0600	0.0200
PB			0.0000	

E.U. 7 Desc: GAS TURBINE #1 FIRED BY #2 FUEL OIL

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
VOC	48.0000		0.0700	0.0200
SO2	346.0000	394.0000	1.9200	0.1800
PM	145.0000	145.0000	0.0700	0.0200
NOX	561.0000		0.9300	0.2700
CO	127.0000		0.2100	0.0600
PM10			0.0700	0.0200
PB			0.0000	

E.U. 8 Desc: BIG BEND STATION UNIT NO. 1 & NO. 2 FLY ASH SILO W

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	22.6200	22.6200	22.6000	22.6000

E.U. 9 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	13.0000	73.1000	22.6000	22.6000

E.U. 10 Desc: BIG BEND COAL YARD.PERMITTED UNDER PA79-12 & PSD-F

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	1212.0000	132.2000	641.0000	1.0000

E.U. 11 Desc: TRUCK UNLOADING OF LIMESTONE

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	3.0000	3.0000	0.1000	0.1000

E.U. 12 Desc: LIMESTONE SILO A W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 13 Desc: LIMESTONE SILO B W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 14 Desc: FLYASH SILO FOR UNIT #4

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.9000	0.9000	1.0000	0.8900

E.U. 15 Desc: UNIT 1 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.9900	0.9900	0.0700	0.0600

E.U. 16 Desc: UNIT 2 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.9900	0.9900	0.0700	

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM	0.9900	0.9900	0.0700	0.0700

E.U. 19 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM			2.6800	3.0000

E.U. 18 Desc: BIG BEND STATION UNIT NO. 1 AND NO. 2 OPEN BED TRU

Pollutant	Poten(TPY)	Allow(TPY)	1995 Actual(TPY)	1994 Actual(TPY)
PM			2.6800	3.0000

DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT SYSTEM
FACILITY EMISSION REPORT

28-OCT-96

AIRS ID: 0570039 # of Emissions Unit: 19
Owner: TECO
Name: BIG BEND STATION
City: RUSKIN Office: SWHI County: HILLSBOROUGH
Status: A Compliance Tracking Code: A DFC: 29-AUG-95
SIC: 4911 PSD: Y PPS: Y NSPS: Y NESHAP:
Title V Source: Y Syn Non-Title V Source: Small Business Stationary:
Major of HAPS: Y Major of Non-HAP Pollutants:
Syn Minor of HAPS: Syn Minor of Non-HAP Pollutants:

E.U. 1 Desc: UNIT #1 COAL FIRED BOILER W/RESEARCH-COTRELL ESP

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	56.0000		37.3000	36.0000
SO2	114936.0000	114936.0000	49677.0000	52675.0000
PM	1770.0000	1770.0000	780.0000	620.0000
NOX	27029.0000		18030.0000	17363.0000
CO	477.0000		319.0000	306.0000
PM10			780.0000	
PB			7.0000	

E.U. 2 Desc: UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	56.0000		0.3900	40.0000
SO2	113766.0000	113766.0000	51428.0000	51314.0000
PM	1752.0000	1752.0000	1350.0000	839.6000
NOX	27118.0000		18914.0000	19636.0000
CO	477.0000		39.0000	348.0000
PM10			1350.0000	
PB			7.0000	

E.U. 3 Desc: UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	58.0000		35.0000	39.0000
SO2	117156.0000	117156.0000	48069.0000	53562.0000
PM	1805.0000	1805.0000	606.0000	537.6000
NOX	12619.0000		7515.0000	7922.0000
CO	499.0000		299.0000	331.0000
PM10			606.0000	
PB			7.0000	

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM10			95.0000	42.0000
PB			10.0000	8.0000

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	43.0000		51.0000	44.0000
SO2	15552.0000	15662.0000	6664.0000	7064.0000
PM	569.0000		95.0000	42.0000
NOX	11379.0000	11379.0000	6593.0000	5898.0000
CO	552.0000		434.0000	380.0000

E.U. 5 Desc: BIG BEND STATION COMBUST. TURBINE #2 - FIRED BY NO

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	162.0000		2.0000	1.0000
SO2	1213.0000	1375.0000	10.0000	7.6300
PM	145.0000	145.0000	2.0000	1.4800
NOX	1958.0000		21.0000	20.1000
CO	447.0000		5.0000	5.0000
PM10			2.0000	
PB				

E.U. 6 Desc: GAS TURBINE #3 - WESTINGHOUSE TURBINE FIRED BY NO.

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	162.0000		1.0000	2.0000
SO2	1213.0000	1375.0000	10.0000	12.5100
PM	145.0000	145.0000	2.0000	2.4300
NOX	1958.0000	1960.0000	21.0000	33.0000
CO	445.0000	445.0000	5.0000	7.0000
PM10			1.0000	
PB				

E.U. 7 Desc: GAS TURBINE #1 FIRED BY #2 FUEL OIL

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
VOC	48.0000			0.1100
SO2	346.0000	394.0000	1.0000	0.6300
PM	145.0000	145.0000		0.1200
NOX	561.0000		2.0000	1.6600
CO	127.0000			0.3700
PM10				
PB				

E.U. 8 Desc: BIG BEND STATION UNIT NO. 1 & NO. 2 FLY ASH SILO W

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	22.6200	22.6200	22.6000	22.6000

E.U. 9 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	13.0000	73.1000	22.6000	22.6000

E.U. 10 Desc: BIG BEND COAL YARD.PERMITTED UNDER PA79-12 & PSD-F

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	1212.0000	132.2000	604.0000	569.0000

E.U. 11 Desc: TRUCK UNLOADING OF LIMESTONE

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	3.0000	3.0000	0.1000	0.1000

E.U. 12 Desc: LIMESTONE SILO A W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 13 Desc: LIMESTONE SILO B W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 14 Desc: FLYASH SILO FOR UNIT #4

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.9000	0.9000	1.0000	0.8800

E.U. 15 Desc: UNIT 1 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.9900	0.9900	0.0600	0.0600

E.U. 16 Desc: UNIT 2 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.9900	0.9900	0.0700	0.0700

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM	0.9900	0.9900	0.0600	0.0700

E.U. 19 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM			3.0000	2.7000

E.U. 18 Desc: BIG BEND STATION UNIT NO. 1 AND NO. 2 OPEN BED TRU

Pollutant	Poten(TPY)	Allow(TPY)	1993 Actual(TPY)	1992 Actual(TPY)
PM			3.0000	2.7000

DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT SYSTEM
FACILITY EMISSION REPORT

28-OCT-96 Page:1

AIRS ID: 0570039 # of Emissions Unit: 19
Owner: TECO
Name: BIG BEND STATION
City: RUSKIN Office: SWHI County: HILLSBOROUGH
Status: A Compliance Tracking Code: A DFC: 29-AUG-95
SIC: 4911 PSD: Y PPS: Y NSPS: Y NESHAP:
Title V Source: Y Syn Non-Title V Source: Small Business Stationary:
Major of HAPS: Y Major of Non-HAP Pollutants:
Syn Minor of HAPS: Syn Minor of Non-HAP Pollutants:

E.U. 1 Desc: UNIT #1 COAL FIRED BOILER W/RESEARCH-COTRELL ESP

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	56.0000		39.3100	23.6000
SO2	114936.0000	114936.0000	63781.6400	36270.0000
PM	1770.0000	1770.0000	549.0700	490.3000
NOX	27029.0000		19073.2600	11452.0000
CO	477.0000		337.7700	202.1000
PM10				
PB				

E.U. 2 Desc: UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	56.0000		32.5800	33.9000
SO2	113766.0000	113766.0000	45168.4500	50721.0000
PM	1752.0000	1752.0000	688.1700	710.6000
NOX	27118.0000		15805.7200	16479.0000
CO	477.0000		280.1100	290.8000
PM10				
PB				

E.U. 3 Desc: UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	58.0000		34.7900	38.8000
SO2	117156.0000	117156.0000	58002.8300	56534.0000
PM	1805.0000	1805.0000	604.5800	954.0000
NOX	12619.0000		7738.2500	8722.0000
CO	499.0000		299.0200	332.8000
PM10				
PB				

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM10				
PB				

E.U. 4 Desc: UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-0

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	43.0000		45.8200	49.0000
SO2	15552.0000	15662.0000	6757.3800	5715.0000
PM	569.0000		43.4700	46.3000
NOX	11379.0000	11379.0000	7039.6300	6951.0000
CO	552.0000		393.4000	420.3000

E.U. 5 Desc: BIG BEND STATION COMBUST. TURBINE #2 - FIRED BY NO

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	162.0000		9.1900	9.0700
SO2	1213.0000	1375.0000	28.8000	93.9000
PM	145.0000	145.0000	2.9800	9.5100
NOX	1958.0000		40.4400	129.0000
CO	447.0000		2.8500	29.3000
PM10				
PB				

E.U. 6 Desc: GAS TURBINE #3 - WESTINGHOUSE TURBINE FIRED BY NO.

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	162.0000		9.6000	7.9500
SO2	1213.0000	1375.0000	30.1000	84.0000
PM	145.0000	145.0000	3.1200	8.3300
NOX	1958.0000	1960.0000	42.2600	113.0000
CO	445.0000	445.0000	2.9700	25.7000
PM10				
PB				

E.U. 7 Desc: GAS TURBINE #1 FIRED BY #2 FUEL OIL

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
VOC	48.0000		0.6300	0.8400
SO2	346.0000	394.0000	6.3500	8.8600
PM	145.0000	145.0000	0.6600	0.8800
NOX	561.0000		8.9100	11.9200
CO	127.0000		2.0200	2.7100
PM10				
PB				

E.U. 8 Desc: BIG BEND STATION UNIT NO. 1 & NO. 2 FLY ASH SILO W

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	22.6200	22.6200	12.9200	13.0000

E.U. 9 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	13.0000	73.1000	10.0000	11.0000

E.U. 10 Desc: BIG BEND COAL YARD.PERMITTED UNDER PA79-12 & PSD-F

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	1212.0000	132.2000	526.6000	556.2000

E.U. 11 Desc: TRUCK UNLOADING OF LIMESTONE

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	3.0000	3.0000	0.0900	0.1000

E.U. 12 Desc: LIMESTONE SILO A W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 13 Desc: LIMESTONE SILO B W/ 2 BAGHOUSES. 1 IS 100% BACK-UP

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.2000	0.2000	0.1000	0.1000

E.U. 14 Desc: FLYASH SILO FOR UNIT #4

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.9000	0.9000	0.7900	0.8200

E.U. 15 Desc: UNIT 1 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.9900	0.9900	0.0700	0.0400

E.U. 16 Desc: UNIT 2 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.9900	0.9900	0.0600	0.0600

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)

E.U. 17 Desc: UNIT 3 COAL BUNKER W/ROTO-CLONE

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM	0.9900	0.9900	0.0600	0.0700

E.U. 19 Desc: FLY-ASH SILO FOR UNIT #3

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM			0.0883	

E.U. 18 Desc: BIG BEND STATION UNIT NO. 1 AND NO. 2 OPEN BED TRU

Pollutant	Poten(TPY)	Allow(TPY)	1991 Actual(TPY)	1990 Actual(TPY)
PM				

Cindy

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 28, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Thomas W. Reese
Attorney at Law
2951 61st Avenue South
St. Petersburg, Florida 33712

Dear Mr. Reese:

RE: Request for Tampa Electric Company's Renewal Dates for Air Permits and Notification of Any Proposed Title V Air Operation Permitting Action

Thank you for your letter of October 8, which requested the renewal dates for Tampa Electric Company's Power Plants. A copy of a permitting history is enclosed for you for the Big Bend facility, the Gannon facility, and the Hookers Point facility. In each of these, you will find the current expiration date for the affected permits. In addition, Rule 62-210.300(2)(a)3.a., F.A.C., extended operation permits for Title V sources subject to Rule 62-213.420(1)(a)1., F.A.C., to 60 days after the due date. Specifically, the due date for these Acid Rain sources was June 15, 1996, pursuant to Rule 62-213.420(1)(a)1.a., F.A.C. The applications for these facilities were received on June 14, 1996. Because of the timely submittal of the initial applications and the initial sufficiency reviews were considered complete, the initial applications were allowed to default to complete 60 days after the June 14 submittal, which was September 12, and Rule 62-213.420(1)(b)2., F.A.C., extended any existing valid permit. The extension of the permits lasts until final agency action is taken on the applications. Copies of the rule citings are enclosed.

The Tampa Electric Company's Polk Power Station facility's construction permit, No. PSD-FL-194, has been extended by amendment (PSD-FL-194A) and expires on June 30, 2000. A copy of the permit extension is enclosed.

Since I specifically work for the Title V Section within the Bureau of Air Regulation, I am assuming that you <u>only</u> desire notification of any proposed agency action regarding the Title V operation permits for the facilities referenced in the preceding paragraph. If this is not accurate, please advise. We have already placed your name on the "to be copied" list in the three proposed Title V permits' Notice of Agency Action documents; and, we will do the same for the Polk Power Station project when it is processed. Therefore, the Department's notification will be mailed to you, the applicant, and others on the same day.

If you desire notification of any proposed air permitting action outside of the Title V Section's, then it is requested that you notify each air permitting authority that might receive and process such a request from the Tampa Electric Company. The following air permitting authorities that might also be involved with the Tampa Electric Company, now and in the future, are:

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 904/488-1344
Fax: 904/922-6979

Contacts: C. H. Fancy, Bureau Chief
A. A. Linero, P.E. Administrator, New Source Review Section

****

Department of Environmental Protection
Southwest District
Air Resources Management
3804 Coconut Palm Drive
Tampa, Florida 33619-821

Telephone: 813/744-6100
Fax: 813/744-6084

Contacts: W. C. Thomas, District Air Program Administrator
G. J. Kissel, P.E. III, Air Permitting Section

****

Hillsborough County Environmental Protection Commission
Air Management Division
1410 North 21st Street
Tampa, Florida 33605

Telephone: 813/272-5530
Fax: 813/272-5605

Contacts: Iwan Choronenko, Director
Jerry Campbell, P.E., Assistant Director.

I hope that your requests have been answered by this letter and enclosures. If not, please give me a call at 904/488-1344 or write to me at the above letterhead address.

Sincerely,

R. Bruce Mitchell

R. Bruce Mitchell
Environmental Administrator
Title V Section-Bureau of Air Regulation

RBM/m

Enclosures

cc: C. H. Fancy, BAR
A. A. Linero, BAR
Patricia Comer, Esq., DEP
W. C. Thomas, SWD
G. J. Kissel, SWD
I. Choronenko, HCEPC
J. Campbell, HCEPC

THOMAS W. REESE
ATTORNEY AT LAW
2951 61ST AVENUE SOUTH
ST. PETERSBURG, FLORIDA 33712

(813) 867-8228
FAX (813) 867-2259

RECEIVED
OCT 11 1996
BUREAU OF
AIR REGULATION

October 8, 1996

Bruce Mitchell
Division of Air Resource Management
Permitting and Standards Section
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: TECO Power Plant Air Permit Renewal Dates

Dear Mr. Mitchell:

Would you please advise me of the air permit renewal dates for each of TECO's power plant plants, especially including each of the Big Bend and Gannon Units.

Also, would you please provide me with actually timely notice of any proposed DEP agency action on any TECO power plant air permits.

Very truly yours,

Thomas W Reese

Thomas W. Reese

cc: Howard Rhodes, Div. Dir.
Bill Thomas, SW Dist. Off.
Jerry Campbell, HCEPC

Appendix H-1, Permit History/ID Number Changes

Tampa Electric Company
Big Bend

[DRAFT/PROPOSED/FINAL]Permit No.: 0570039-002-AV
Facility ID No.: 0570039

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date	Revised Date(s)
-001	Unit 1 Coal Fired Boiler	AO29-219924	11/24/92	12/01/97		
-002	Unit 2 Coal Fired Boiler	AO29-179912	11/19/90	10/18/95	08/14/96	
-003	Unit 3 Coal Fired Boiler	AO29-179911	08/29/90	08/30/95	08/14/96	
-004	Unit 4 Coal Fired Boiler	PSD-FL-040	11/14/81			
-005	Combustion Turbine #2	AO29-174596	03/14/90	03/09/95	08/14/96	
-006	Gas Turbine #3	AO29-174611	05/08/90	04/27/95	08/14/96	
-007	Gas Turbine #1	AO29-160257	01/19/90	07/07/94		
-008	Unit #1 & #2 Flyash Silo	AO29-160255	01/19/90	12/22/94		
-009	Fly Ash Silo for Unit #3	AO29-161082	10/16/91	07/07/94		
-010	Big Bend Coal Yard	PSD-FL-040	11/14/81			
-011	Truck Unloading of Limestone	PSD-FL-040	11/14/81			
-012	Limestone Silo A w/2 baghouses	PSD-FL-040	11/14/81			
-013	Limestone Silo B w/2 baghouses	PSD-FL-040	11/14/81			
-014	Flyash Silo for Unit #4	PSD-FL-040	11/14/81			
-015	Unit 1 Coal Bunker w/Rotoclone	AO29-163788	10/06/89	06/30/94		
-016	Unit 2 Coal Bunker w/Rotoclone	AO29-163788	10/06/89	06/30/94		
-017	Unit 3 Coal Bunker w/Rotoclone	AO29-163788	10/06/89	06/30/94		
-018	Fly Ash Silo for Unit #3	AO29-161082	10/16/91	07/07/94		
-019	Big Bend Station Unit #1 & #2	Ao29-160255	01/19/90	12/22/94		

(if applicable) ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 40HIIL290039

To: **Facility ID No.:** 0570039

Appendix H-1, Permit History/ID Number Changes

Tampa Electric Company
F. J. Gannon

[DRAFT/PROPOSED/FINAL]Permit No.: 0570040-002-AV
Facility ID No.: 0570040

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Extended Date	Revised Date(s)
-001	Steam Generator	AO29-204434	1/31/92	1/31/97		10/11/94
-002	Boiler	AO29-189206	2/7/91	2/6/96	8/14/96	
-003	Coal Fired Boiler	AO29-172179	4/26/90	4/19/95	8/14/96	10/11/94
-004	Coal Fired Boiler	AO29-255208	12/2/94	10/14/99		
-005	Coal Fired Boiler	AO29-203511	1/1/92	1/1/97		
-006	Coal Fired Boiler	AO29-203512	2/15/92	2/15/97		
-007	Gas Turbine	AO29-252615	8/31/94	8/31/99		
-008	Boiler	AO29-216480	4/23/93	9/12/97		
-009	Economizer Ash Silo	AO29-218858	8/29/89	11/6/97		
-010	Fly Ash Silo	AO29-250137	7/20/94	7/12/99		2/6/95
-011	Fly Ash Silo	AO29-250140	7/20/94	7/12/99		2/6/95
-012	Pug Mill & Truck Loading	AO29-250137	7/20/94	7/12/99		2/6/95
-013	Unit 1 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-014	Unit 2 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-015	Unit 3 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-016	Unit 4 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-017	Unit 5 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95
-018	Unit 6 Coal Bunker w/Rotoclone	AO29-250139	7/20/94	7/12/99		2/6/95

(if applicable) ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 40HIL290040

To: **Facility ID No.:** 0570040

Appendix H-1, Permit History/ID Number Changes

Tampa Electric Company
Hooker's Point

[DRAFT/PROPOSED/FINAL]Permit No.: 0570038-001-AV
Facility ID No.: 0570038

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date	Revised Date(s)
-001	Oil-Fired Boiler #1	AO29-203001	12/19/91	12/01/96		
-002	Oil-Fired Boiler #2	AO29-203000	12/19/91	12/01/96		
-003	Oil-Fired Boiler #3	AO29-202999	12/19/91	12/01/96		
-004	Oil-Fired Boiler #4	AO29-202998	12/19/91	12/01/96		
-005	Oil-Fired Steam Generator #6	AO29-202997	12/19/91	12/01/96		

(if applicable) ID Number Changes (for tracking purposes):

From: **Facility ID No.:** 40HIL290038

To: **Facility ID No.:** 0570038

(v) Cyclic, branched, or linear completely methylated siloxanes

(w) Acetone

(x) Perfluorocarbon compounds which fall into these classes:

1. Cyclic, branched, or linear, completely fluorinated alkanes;

2. Cyclic, branched, or linear, completely fluorinated ethers with no unsaturations;

3. Cyclic, branched, or linear, completely fluorinated tertiary amines with no unsaturations; and

4. Sulfur containing perfluorocarbons with no unsaturations and with sulfur bonds only to carbon and fluorine.

(310) "Waste-to-Energy Facility" - A facility that uses an enclosed device using controlled combustion to thermally break down solid, liquid or gaseous combustible solid waste to an ash residue that contains little or no combustible material, and that produces electricity, steam, or other energy as a result. The term does not include facilities that primarily burn fuels other than solid waste, even if the facilities also burn some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel. For the purposes of Rule 62-296.416, F.A.C., the term does not include facilities that primarily burn biohazardous or hazardous waste and industria boilers that burn pelletized paper waste as a supplemental fuel.

(311) "Waxy, Heavy Pour Crude Oil" - A crude oil with a pour point of 50 degrees or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils". A copy of the above referenced document is available from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103, and may be examined at the Department's Tallahassee office.

(312) "Yard Trash" - Vegetative matter resulting from landscaping and yard maintenance operations which includes materials such as tree and shrub trimmings, grass clippings, palm fronds, trees and tree stumps.

Specific Authority 403.061, FS.
Law Implemented 403.021, 403.031, 403.061, 403.087, FS.
History -- Formerly 17-2.100; Amended 2-9-93, 11-28-93, Formerly 17-210.200, Amended 11-23-94, 4-18-95, 1-2-96, 3-13-96, 3-21-96, 8-15-96.

62-210.300 Permits Required. The owner or operator of any emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, modification, or initial or continued operation of the emissions unit unless exempted pursuant to Department rule or statute. All emissions limitations, controls, and other requirements imposed by such permits shall be at least as stringent as any applicable limitations and requirements contained in or

enforceable under the State Implementation Plan (SIP) or that are otherwise federally enforceable. Issuance of a permit does not relieve the owner or operator of any emissions unit from complying with applicable emission limiting standards or other requirements of the air pollution rules of the Department, or any other applicable requirements under federal, state, or local law.

(1) Air Construction Permits. An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification, in accordance with all applicable provisions of this chapter, Chapter 62-212 and Chapter 62-4, F.A.C. The construction permit shall be issued for a period of time sufficient to allow construction or modification of the facility or emissions unit and operation while the new or modified facility or emissions unit is conducting tests or otherwise demonstrating initial compliance with the conditions of the construction permit.

(2) Air Operation Permits. Upon expiration of the air operation permit for any existing facility or emissions unit, subsequent to construction or modification and demonstration of initial compliance with the conditions of the construction permit for any new or modified facility or emissions unit, or as otherwise provided in this chapter or Chapter 62-213, the owner or operator of such facility or emissions unit shall obtain a renewal air operation permit, an initial air operation permit, or an administrative correction or revision of an existing air operation permit, whichever is appropriate, in accordance with all applicable provisions of this chapter, Chapter 62-213 (if the facility is a Title V source), and Chapter 62-4, F.A.C.

(a) Minimum Requirements for All Air Operation Permits. At a minimum, a permit issued pursuant to this subsection shall:

1. Specify the manner, nature, volume and frequency of the emissions permitted, and the applicable emission limiting standards or performance standards, if any;

2. Require proper operation and maintenance of any pollution control equipment by qualified personnel, where applicable in accordance with the provisions of any operation and maintenance plan required by the air pollution rules of the Department.

3. Contain an effective date stated in the permit which shall not be earlier than the date final action is taken on the application and be issued for a period, beginning on the effective date, as provided below.

a. The operation permit for an emissions unit which is in compliance with all applicable rules and in operational condition, and which the owner or operator intends to continue operating, shall be issued or renewed for a five-year period, except that, for Title V sources subject to Rule 62-213.420(1)(a)1., F.A.C., operation permits shall be extended until 60 days after the due date for submittal of the facility's Title V permit application as specified in Rule 62-213.420(1)(a)1., F.A.C.

b. Except as provided in Rule 62-210.300(2)(a)3.d., F.A.C., the operation permit for an emissions unit which has been shut down for six months or more permit may include such emissions unit in the initial application, provided the requirements of Rule 62-213.420(3)(k), F.A.C., are met.

(b) Complete Application.

1. Any applicant for a Title V permit, permit revision or permit renewal must submit an application on form number 62-210.900(1), which must include all the information specified by Rule 62-213.420(3), F.A.C., except that an application for permit revision must contain only that information related to the proposed change. The applicant shall include information concerning fugitive emissions and stack emissions in the application. Each application for permit, permit revision or permit renewal shall be certified by a responsible official in accordance with Rule 62-213.420(4), F.A.C.

2. For those applicants submitting initial permit applications pursuant to Rule 62-213.420(1)(a)1., F.A.C., a complete application shall be an application that substantially addresses all the information required by the application form number 62-210.900(1), and such applications shall be deemed complete within sixty days of receipt of a signed and certified application unless the Department notifies the applicant of incompleteness within that time. For all other applicants, the applications shall be deemed complete sixty days after receipt, unless the Department, within sixty days after receipt of a signed application for permit, permit revision or permit renewal, requests additional documentation or information needed to process the application. An applicant making timely and complete application for permit, or timely application for permit renewal as described by Rule 62-4.090(1), F.A.C., shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, provided the applicant complies with all the provisions of Rule 62-213.420(1)(b)3. and 4. F.A.C. Failure of the Department to request additional information within sixty days of receipt of a properly signed application shall not impair the Department's ability to request additional information pursuant to Rule 62-213.420(1)(b)3. and 4., F.A.C.

3. For those permit applications submitted pursuant to the provisions of Rule 62-213.420(1)(a)1., F.A.C., the Department shall notify the applicant if the Department becomes aware at any time during processing of the application that the application contains incorrect or incomplete information. The applicant shall submit the corrected or supplementary information to the Department within ninety days unless the applicant has requested and been granted additional time to submit the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days or such additional time as requested and granted shall render the application incomplete.

4. For all applications other than those addressed at Rule 62-213.420(1)(b)3., F.A.C., should the Department become aware, during processing of any application that the application contains incorrect information, or should the Department become aware, as a result of comment from an

affected State, an approved local air program, EPA, or the public that additional information is needed to evaluate the application, the Department shall notify the applicant within 30 days. When an applicant becomes aware that an application contains incorrect or incomplete information, the applicant shall submit the corrected or supplementary information to the Department. If the Department notifies an applicant that corrected or supplementary information is necessary to process the permit, and requests a response, the applicant shall provide the information to the Department within ninety days of the Department request unless the applicant has requested and been granted additional time to submit the information or, the applicant shall, within ninety days, submit a written request that the Department process the application without the information. Failure of an applicant to submit corrected or supplementary information requested by the Department within ninety days, or such additional time as requested and granted, or to demand in writing within ninety days that the application be processed without the information shall render the application incomplete. Nothing in this section shall limit any other remedies available to the Department.

5. All Department requests for additional information shall conform to the requirements of Rule 62-4.055(2), (3), and (4), F.A.C.

6. The Department shall grant requests for additional time to submit supplemental or corrected information as follows:

a. Each source requesting additional time must make a written request prior to the due date for receipt of the
information and must specify the number of additional days requested;

b. The Department shall grant up to sixty additional days to any source operating in compliance with the terms and conditions of the source's existing valid permit without the need to show cause;

c. The Department shall grant additional time beyond sixty days or to sources not operating in compliance with existing valid permits only after the source demonstrates good cause. Good cause shall mean any unforeseen situation outside the control of the source such as labor strikes, acts of war, extraordinary or sudden and unexpected acts of nature or accidents beyond the control of the source. If the Department has required, in the request for additional or corrected information, that the source undertake specific testing or investigation, good cause shall also include the requirement to complete any required tests or investigation that cannot be completed within 150 days, so long as the source specifies the expected date of completion in its demonstration of good cause and so long as the estimated time requested is for the work required.

(2) Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA.

(3) Standard Application Form and Required Information. Applications shall be submitted under this chapter on forms provided by the Department and adopted by reference in Rule 62-210.900(1), F.A.C. The information as described in Rule 62-210.900(1), F.A.C., shall be included for the Title V source and each emissions

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

February 28, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. G. F. Anderson
Tampa Electric Company
P. O. Box 111
Tampa, Florida 33601-0111

Dear Mr. Anderson:

RE: Amendment for a Modification to the Auxiliary Boiler
and Expiration Date Extension
PSD-FL-194(A)

The Department received your requests of May 12 and June 9, 1994, to modify the auxiliary boiler by increasing the heat input rate, which will require changing some existing specific conditions, and to extend the expiration date of the PSD permit referenced below. The permit is amended as shown:

Permit No. PA-92-32, PSD-FL-194, Tampa Electric Company.

Current Expiration Date: June 1, 1996

New Expiration Date: June 30, 2000

The Department is also modifying the specific conditions as follows:

E. Auxiliary Boiler

The maximum heat input to the auxiliary boiler shall not exceed ~~49.5~~ 120.0 MMBtu/hr when firing No. 2 fuel oil with 0.05 percent maximum sulfur content by weight. All fuel consumption must be continuously measured and recorded for the auxiliary boiler.

G. Fugitive Dust

Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas. Particulate matter emissions from the coal handling equipment shall be controlled by enclosing all coal storage, conveyors and conveyor transfer points (~~except-those-directly-associated-with-the-coal stacker/reclaimer-for-which-an-enclosure-is-operationally infeasible~~). Fugitive emissions shall be tested as specified in Condition No. J. ~~Inactive-coal-storage-shall-be-shaped,-compacted, and-oriented-to-minimize-wind-erosion.~~ Water sprays or chemical wetting agents and stabilizers shall be applied to uncovered storage piles, roads, handling equipment, etc. during dry periods and, as necessary, to all facilities to maintain an opacity of less than or equal to five percent. ~~When-adding,-moving-or-removing coal-from-the-coal-pile,-an-opacity-of-20-percent-is-allowed.~~

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

			Emissions Limitations 7F CT Postdemonstration Period	
Pollutant	Fuel	Basis	lb/hr	tpy
NO_x	Oil	42 ppmvd	311	N/A
	Syngas	25 ppmvd	~~222.5~~ 220.25	~~1,044~~ 1,032.9

I. Auxiliary Boiler Operation

Normal operation of the auxiliary boiler shall be limited to a maximum of ~~1,000~~ 3,000 hours per year ~~and-only-during-periods-of startup-and-shutdown-of-the-IGCC-unit,-or-when-steam-from-the-IGCC unit's-heat-recovery-steam-generator-is-unavailable.~~ The auxiliary boiler may operate continuously (i.e. 8,760 hrs/yr) in the standby mode. The following emission limitations shall apply:

1. NO_x emissions shall not exceed ~~0.16~~ 0.10 lbs/MMBtu for oil firing.
2. Sulfur dioxide emissions shall be limited by firing low sulfur oil with a maximum sulfur content of 0.05 percent by weight.
3. Visible emissions shall not exceed 20 percent opacity (6-minute average) ~~(~~except for one six-minute period per hour during which opacity shall not exceed 27 percent~~)~~, while burning low sulfur fuel oil.

L. Monitoring Requirements

1. IGCC Combustion Turbine

A continuous emission monitoring system (CEMS) shall be installed, operated and maintained in accordance with 40 CFR 60, Appendix F, for the combined cycle unit to monitor nitrogen oxides and a diluent gas (CO_2 or O_2). The applicant shall request that this condition of certification be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75, if applicable, when those requirements become effective within the state.

~~1.~~ a Each CEMS shall meet the performance specifications of 40 CFR 60, Appendix B.

~~2.~~ b CEMS data shall be recorded and reported in accordance with Rule ~~Chapter~~ 62-297.500, F.A.C.; 40 CFR 60; and, 40 CFR 75, if applicable. The record shall include periods of startup, shutdown, and malfunction.

~~3.~~ c A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition, or preventable equipment breakdown shall not be considered malfunctions.

~~4.~~ d The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS.

~~5.~~ e For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition No. H.4 herein, which exceeds the applicable emission limits in Condition No. H.1.

2. Auxiliary Boiler

A CEMS shall be installed, operated and maintained in accordance with 40 CFR 60, Appendix F, for the auxiliary boiler to monitor nitrogen oxides emissions and in accordance with 40 CFR 60.13 to monitor opacity.

a. The CEMS shall meet the performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Rule 62-297.500, F.A.C., and 40 CFR 60. The record shall include periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

N. Applicable Requirements

The project shall comply with all the applicable requirements of Chapters 62-212 and 62-4, F.A.C., and 40 CFR 60, Subparts A, Db and GG.

A copy of this letter shall be attached to the above mentioned permit, No. PSD-FL-194(A), and shall become a part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/sa/b

cc: B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
H. Oven, PPS
T. Davis, P.E., ECT

Environmental Consulting & Technology, Inc.

RECEIVED
AUG 19 1996
BUREAU OF
AIR REGULATION

August 16, 1996

Ms. Cindy Phillips
Florida Department of Environmental Protection
111 Magnolia Drive, Suite 13
Tallahassee, FL 32308

Re: Tampa Electric Company
Big Bend Station
Title V Attachment Files

Dear Ms. Phillips:

Pursuant to our recent telephone conversation, please find enclosed four diskettes containing a zipped attachment file for the Tampa Electric Company (TEC) Big Bend Station. The following file is provided on the enclosed diskettes:

- TEC_BB.ZIP

Please call me at 352/332-6230, extension 350 if you have any questions regarding these files.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Alan M. Trbovich
Senior Scientist

AMT/edd

Enclosure

cc: Ms. Janice Taylor, TEC
Mr. Tom Davis, ECT

3701 Northwest 98TH Street
Gainesville, FL 32606
(352) 332-0444
FAX (352) 332-6722

Florida Department of

Environmental Protection

Memorandum

RECEIVED
AUG 14 1996
BUREAU OF AIR REGULATION

TO: Cindy Phillips

FROM: Terry Knowles

DATE: August 12, 1996

SUBJECT: Tampa Electric Company ELSA Submittal

Cindy, both John Strand and I have spoken to Janice Taylor with Tampa Electric Company regarding their ELSA submittal. The application will not upload due to the precision on several fields in the Segment record of the application.

Our database will not accept more than one decimal point in certain fields. However, the version of ELSA they used to submit their application does allow them to submit the data to disk even though these fields sizes are too large. This explains why they were able to submit two other applications with no problems. We have corrected this problem in the latest version of ELSA.

I have talked to both Yi Zhu and Scott Sheplak about the issue of precision in these fields because many users have indicated they want to submit the data accurately. In order to accept the data at this precision, we will need to modify ELSA, EARS and ARMS to accept the data. Please let me know your thoughts with regard to this data. I will be happy to have the database changes made if they are necessary.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

RECEIVED
JUN 14 1996
BUREAU OF
AIR REGULATION

June 13, 1996

RECEIVED
JUN 14 1996
BUREAU OF
AIR REGULATION

VIA FEDEX AIRBILL #9737560932

Mr. John C. Brown, P.E.
Administrator-Title V Programs
MS 5505
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Tampa Electric Company
Big Bend Station
AIRS No. 0570039
Title V Permit Application

Dear Mr. Brown:

Enclosed please find four (4) copies of the Title V permit application signed and sealed for the above referenced facility in accordance with 62-4.050 and 62-213.420, F.A.C.

As indicated in the permit application, please address any comments or concerns to me, as follows,

Tampa Electric Company
Janice K. Taylor
Senior Engineer
P.O. Box 111
Tampa, FL 33601-0111

Ph. No. (813) 228-4839
Fax No. (813) 228-4881

702 FRANKLIN STREET
TAMPA 33601

Put these in comment section if you absolutely want to enter them otherwise go with greater number

Thank you in advance for your consideration in this matter.

Sincerely,

Janice K. Taylor
Senior Engineer
Environmental Planning

Viruses Scanned
y/k3
06/14/96

Enclosures

EP\sn\JKT757

USING V1.2.1
REQUESTED ANOTHER SET 7/30/96
KBN SUBMITTAL(?)
JUST ONE DISK NOT 4

SENT DISKETTES BACK TO ECT ON MONDAY 8/12/96

BEST AVAILABLE COPY

ECT
Environmental Consulting & Technology, Inc.

RECEIVED

AUG 13 1996

DIVISION OF AIR
RESOURCES MANAGEMENT

August 12, 1996

SENT BY OVERNIGHT MAIL ON 08/12/96

Mr. John Strand
Florida Department of Environmental Protection
111 Magnolia Drive, Suite 23
Tallahassee, FL 32308

Re: Tampa Electric Company
Big Bend Station
Title V ELSA Files

Dear Mr. Strand:

Pursuant to our recent telephone conversation, please find enclosed four (4) diskettes containing revised ELSA Version 1.2.1 input and submit files for the Tampa Electric Company (TEC) Big Bend Station. The following six (6) files are provided on the enclosed diskettes:

- ELSA.LDB;
- ELSA.MDB;
- ELSA.TXT;
- SYSTEM.LDB;
- SYSTEM.MDA; and
- BIGBEND.ZIP

The first five files are those used as input to ELSA Version 1.2.1 while the last file is the submit file created by ELSA. As requested, segment fields for Emission Units 5, 6, and 7 (Combustion Turbines Nos. 1, 2, and 3, respectively) were revised by deleting the data contained in several fields [Segment Data, Field 4 (maximum hourly rate) and Field 8 (maximum percent ash) for Emission Unit 5 and Segment Data, Field 8 for Emission Units 6 and 7) and placing the same information in the comment field.

Please call me at (352) 332-6230, Ext. 351 if you have any questions regarding these files.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

Enclosure

cc: Ms. Janice Taylor, TEC
Mr. Al Trbovich, ECT

3701 Northwest
98TH Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

ECT
Environmental Consulting & Technology, Inc.

August 5, 1996

SENT BY OVERNIGHT MAIL ON 08/05/96

Mr. John Strand
Florida Department of Environmental Protection
111 Magnolia Drive, Suite 23
Tallahassee, FL 32308

**Re: Tampa Electric Company
Big Bend Station
Title V ELSA Files**

Dear Mr. Strand:

Pursuant to our recent telephone conversation, please find enclosed a diskette containing ELSA Version 1.2.1 input files for the Tampa Electric Company (TEC) Big Bend Station. The following five (5) files are provided on the enclosed diskette:

- ELSA.LDB;
- ELSA.MDB;
- ELSA.TXT;
- SYSTEM.LDB; and
- SYSTEM.MDA

Please call me at (352) 332-6230, Ext. 351 if you have any questions regarding these files.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

Enclosure

cc: Ms. Janice Taylor, TEC
Mr. Al Trbovich, ECT

3701 Northwest
98TH Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

Memorandum

Florida Department of
Environmental Protection

TO: Iwan Choronenko, Director
Local Program Air Permitting Administrator

FROM: Bruce Mitchell BM

DATE: August 12, 1996

SUBJECT: Completeness Review of an Application Package for a Title V Operation Permit
Big Bend Station: 0570039-002-AV

Enclosed is an application package for a Title V operation permit that is being processed in Tallahassee. Please have someone review the package for completeness and respond in writing by September 9, if you have any comments. Otherwise, no response is required. If there are any questions, please call the project engineer, Cindy Phillips, at 904/488-1344 or SC:278-1344. It is very important to verify the compliance statement regarding the facility. Since we do not have a readily effective means of determining compliance at the time the application was submitted, please advise if you know of any emissions unit(s) that were not in compliance at that time and provide supporting information. Also, do not write on the documents.

If there are any questions regarding this request, please call me or Scott Sheplak at the above number(s).

RBM/bm

Enclosure

TAMPA ELECTRIC
A TECO ENERGY COMPANY

August 1, 1996

Ms. Cindy L. Phillips
Title V Programs
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

VIA FEDEX
AIRBILL #9737561094

RECEIVED
AUG 2 1996
BUREAU OF
AIR REGULATION

RE: **Tampa Electric Company**
Big Bend Station
AIRS No. 0570039
Title V Permit Application

Dear Ms. Phillips:

Pursuant to my conversation with John Strand of the Florida Department of Environmental Protection, please find enclosed four (4) new copies of the Title V permit application. Please let me know if you have any further trouble opening these disks.

As indicated in the permit application, please address any comments or concerns to me, as follows:

Tampa Electric Company
Janice K. Taylor
Senior Engineer
P.O. Box 111
Tampa, FL 33601-0111

Ph. No. (813) 228-4839
Fax No. (813) 228-4881

Thank you in advance for your consideration in this matter.

Sincerely,

Janice K. Taylor
Senior Engineer
Environmental Planning

Enclosures

EP\gm\JKT770

(FOR INTERNAL USE ONLY)

State of Florida summary checklist for initial Title V permit applications for 'existing' Title V Sources (cont'd)

TECO - Big Bend Station

II. Application logging.

ARMS Permit Number assigned 0570039-002-AV

logged into ARMS by initials B.M. date 07/19/96

III. Initial distribution of application.

a. Disposition of 4 paper/electronic copies submitted:

1- Clean originals to file? Y____ N____

1- ____ District Y____ N____

1- ___________ County [affected local program]? Y____ N____

1- Permit engineer(s) _________________, _________________

b. Disposition of electronic files submitted:

copy placed onto PC? Y____ N____

c. Disposition of ELSA submitted:

version used [circle]: 1.0 1.1 1.2.1 1.3 1.3a 1.3b

Uploaded to EARS? Y____ N____

by _______ date ___/___/___

d. Electronic information submitted previewed? Y____ N____ N/A____

Comment(s):

{this checklist was developed from Rule 62-213.420(1)(b)2., F.A.C. and DARM policy}

6/11/96

:\t5opgen\0_check\iapcheck.doc

(FOR INTERNAL USE ONLY)

State of Florida summary checklist for initial Title V permit applications for 'existing' Title V Sources

Facility Owner/Operator Name: Tampa Electric Company
Facility ID No.: 0570039 Site Name: Big Bend Station
County: Hillsborough
application receipt date 06 / 14 / 96

I. Preliminary scanning of application submitted.

a. Was application submitted to correct permitting authority? Y ✓ N____
b. Was an application filed? Y* ✓ N____
c. Was the application filed timely? Y* ✓ N____

d. Application format filed [check one]. Version 1.2.1
Hard copy of official version of form? ____ ELSA? ✓ w/ hard copy attachments
A facsimile of official version of form? ____ Some combination? ____

e. 4 copies (paper/electronic) submitted? Y ✓ N____

f. Electronic diskettes protected/virus scanned/marked? Y ✓ N____ N/A____
by KZ. date 06 / 14 / 96

g. Entire hard copy of Section I. provided (Pages 1-8 of form)? Y____ N ✓ ELSA
Facility identified (Page 1)? [if not complete a Page 1] Y*____ [Attached____]
R.O. certification signed and dated (Page 2)? Y* ✓ N____
P.E. certification signed and dated (Page 7)? Y* ✓ N____

h. Any confidential information submitted? Y____ N ✓
If yes, R.O. provided hard copy to us and EPA? Y*____ N____
If yes, hard copy locked up and note filed with application? Y*____ N____

i. Type of application filed.
TV application for 'existing' Title V Source only? Y ✓ N____
Any units subject to acid rain? Y ✓ N____

Note(s): [*] = mandatory.

Comment(s):____

Reviewer's initials BB date 06 / 17 / 96 Concurrence initials ____ date __/__/__

TAMPA ELECTRIC
A TECO ENERGY COMPANY

RECEIVED

JUN 14 1996

BUREAU OF
AIR REGULATION

June 13, 1996

Mr. John C. Brown, P.E.
Administrator-Title V Programs
MS 5505
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

VIA FEDEX AIRBILL #9737560932

RECEIVED

JUN 14 1996

BUREAU OF
AIR REGULATION

RE: **Tampa Electric Company**
Big Bend Station
AIRS No. 0570039
Title V Permit Application

Dear Mr. Brown:

Enclosed please find four (4) copies of the Title V permit application signed and sealed for the above referenced facility in accordance with 62-4.050 and 62-213.420, F.A.C.

As indicated in the permit application, please address any comments or concerns to me, as follows,

Tampa Electric Company
Janice K. Taylor
Senior Engineer
P.O. Box 111
Tampa, FL 33601-0111

Ph. No. (813) 228-4839
Fax No. (813) 228-4881

Thank you in advance for your consideration in this matter.

Viruses Scanned
ykz 06/14/96

Sincerely,

Janice K. Taylor
Senior Engineer
Environmental Planning

Enclosures

EP\sn\JKT757

THOMAS W. REESE
ATTORNEY AT LAW
2951 61ST AVENUE SOUTH
ST. PETERSBURG, FLORIDA 33712

(813) 867-8228
FAX (813) 867-2259

RECEIVED
OCT 11 1996
BUREAU OF
AIR REGULATION

October 8, 1996

Bruce Mitchell
Division of Air Resource Management
Permitting and Standards Section
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: TECO Power Plant Air Permit Renewal Dates

Dear Mr. Mitchell:

Would you please advise me of the air permit renewal dates for each of TECO's power plant plants, especially including each of the Big Bend and Gannon Units.

Also, would you please provide me with actually timely notice of any proposed DEP agency action on any TECO power plant air permits.

Very truly yours,

Thomas W Reese

Thomas W. Reese

cc: Howard Rhodes, Div. Dir.
Bill Thomas, SW Dist. Off.
Jerry Campbell, HCEPC

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 9, 1996

Mr. Peter Tsirigotis
US EPA
Office of Air and Radiation
401 M Street SW (6204J)
Washington, DC 20460

Subject: Acid Rain Program: Proposed Rule for Nitrogen Oxides
Tampa Electric Company
Information from a recent inspection

Dear Mr. Tsirigotis:

Earlier this year Sargent & Lundy along with Carnot under contract to Tampa Electric Company (TECO) compiled a study of NOx controls for the four cyclone and the five Riley Stoker wet bottom turbo boilers operated by TECO. This study, entitled Nitrogen Oxide Limitation Study, was submitted to your office and TECO provided a copy to the state and county agencies. The report concludes that the acid rain program's proposed controls and NOx limits for group 2 boilers **should not apply** to the TECO boilers for many reasons. Although the five wet bottom turbo boilers(capacity factors 60-80 percent range) are utilized more than the cyclone units, they are reported to have potential NOx reductions of less than 25% from combustion controls. In the final rule, add on controls such as SCR or SNCR, and fuel switching (as discussed below) may be needed as control options in addition to the proposed rule's combustion controls for these wet bottom turbo boilers to obtain reductions in emissions sufficient to meet 0.86 lb/mmBtu.

After reading the study, I had several questions. On September 16, 1996 I visited the Big Bend and Gannon facilities in Tampa to obtain answers and further evaluate the various options for retrofitting NOx controls on these group 2 boilers. I was surprised to find NOx emissions from two cyclone units, at or below the proposed limits of 0.94 lb/mmBtu (operation was near full load). TECO personnel had no explanation for the low emission rates but stated that NOx emissions can vary from these units. During my visit I noted that these units had recently switched to Powder River Basin coal. During a visit on August 16, a representative from the Hillsborough County Environmental Protection Commission noted that NOx emissions from the two wet bottom turbo units at the Gannon station were below the proposed limits of 0.86 lb/mmBtu (no record of coal type, operation on Gannon Unit 5 was less than half load, operation on unit 6 was near full load). Apparently fuel switching for SO_2 allowances may have a co-benefit of reducing NOx.

Big Bend Unit 3, one of the five wet bottom boilers operated by TECO, has operated at annual emission rates of 0.60 to 0.70 lb/mmBtu since the mid 1970's. Unit 3 is not subject to NSPS but has a NOx limit established in the Florida Administrative Code. All of the turbo-fired units have opposed wall burners and a furnace which narrows (forming the turbo throat) above the downward tilted burners. Water tube platens located above the turbo throat protrude into the furnace box. They were installed after the initial design to improve heat transfer. Unit 3, the low NOx wet bottom boiler, has these same water tube platens, although in a slightly different arrangement than the other four wet bottom turbos. Although all the wet bottom turbo boilers appear similar in design, the Sargent & Lundy report does not address this critical question:

> Can Big Bend Units 1 and 2 and Gannon Units 5 and 6 be modified to achieve less than 0.70 lb/mmBtu as Unit 3 has at Big Bend?

Oddly enough, the study evaluated Unit 3 for NOx controls even though actual emissions are well below (25%) the proposed standard. TECO staff have explained that Unit 3 differs from the earlier wet bottom units in that it has a larger furnace. My inspection revealed that the plan area of Unit 3 is only about 11 percent larger than Unit 2 although emission rates are about twice as high on Unit 2. The attached table gives information which may be useful in evaluating the differences in these wet bottom turbo units.

Emission controls on the TECO group 2 boilers could be very important as the Tampa Bay area has experienced four(4) exceedances of the ozone standard over the past two years. Also, impacts to Tampa Bay due to high nitrate loadings have caused loss of sea grass and aquatic life over the past 30 years. Annual NOx emissions from the two TECO facilities in the Tampa Bay area were 88,000 tpy in 1994, an increase of 7 percent over 1990 levels.

Please keep me informed on any changes to the Phase II NOx standards and control requirements as they affect the TECO group 2 units. Call me at (904) 488-1344 or email (COSTELLO_M@DEP.STATE.FL.US) if I can assist you in any way

Sincerely,

Martin Costello

Martin Costello, P.E.
Bureau of Air Regulation

cc: Jerry Campbell
Jerry Kissel
Patrick Ho

Attachment

NOx EMISSIONS FROM TECO WET BOTTOM TURBO UNITS

	Big Bend U3	**Big Bend U2**
Emission limit(lb/mmBtu)	**0.70**	**none**
Boiler Rating (MW)	445	445
Installed	1976	1973
furnace width	61′ 9″	61′ 9″
furnace depth	**36′ 0″**	**32′ 0″**
Emission rate(lb/mmBtu)	0.65	1.39

note: Big Bend Unit 1 (445 MW) and Gannon Unit 5 (239 MW) and Unit 6 (414 MW) are similar in design and have similar emission rates compared to Big Bend Unit 2

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 9, 1996

Mr. Patrick A. Ho, Manager of Environmental Planning
Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Subject: Request for Information

Dear Mr. Ho:

Earlier this year Sargent & Lundy along with Carnot compiled a study of NOx controls for the four cyclone and the five Riley Stoker wet bottom turbo boilers operated by TECO. A copy of this study entitled Nitrogen Oxide Limitation Study was submitted to the Department. The conclusions from this study explained that the proposed controls and NOx limits for group 2 boilers should not apply to the TECO boilers for many reasons. If NOx standards were imposed, the five wet bottom turbo boilers are reported to have potential NOx reductions of less than 25% from combustion controls.

After reading the study, I had several questions. On September 16 I visited the Big Bend and Gannon facilities to obtain answers and further evaluate the various options for retrofitting NOx controls on these group 2 boilers. I was surprised to find NOx emissions from two cyclone units, at or below the proposed EPA limits of 0.94 lb/mmBtu (operation was near full load). TECO personnel had no explanation for the low emission rates but stated that NOx emissions can vary from these units. During my visit I noted that these units had recently switched to Powder River Basin coal. During a visit on August 16, a representative from Hillsborough County Environmental Protection Commission noted that NOx emissions from the two wet bottom turbo units at the Gannon station were below the proposed levels of 0.86 lb/mmBtu (no record of coal type, operation on Gannon Unit 5 was less than half load, operation on Unit 6 was near full load). Can you confirm if fuel switching for SO_2 allowances have a co-benefit of reducing NOx? Can you explain what properties of the fuel, (i.e. fuel bound nitrogen, Btu value, water content) contribute most to the reduced emission rates for NOx and how the combustion process is affected by these fuel properties?

Although the TECO personnel were very helpful during my visit, there were several requests which I was asked to submit in writing. The following items are requested:

- Boiler diagrams for all group 2 units like the ones posted at the plant which show dimensions.
- Flue gas properties for the wet bottom turbos and cyclones which are important for NOx formation; including burner zone heat release rates (BZHRR), residence times, and temperatures.
- Operating data which indicate the range of operation (i.e. are the cyclones operated at less than 50% of rated load, how often...).

- Any limits specified in contracts or otherwise required on the ammonia content of ash used for mixing with concrete
- Any limits specified in contracts or otherwise required on the ammonia content of ash used for making cement.
- Percentages of each of the above ash products sold(i.e. 50% sold for mixing with concrete and 50% sold for cement manufacturing).

Finally, I would like to see a comparison of Big Bend Unit 3 with the other wet bottom turbos in terms of boiler dimensions, design, and operation as they relate to NOx control. The Sargent and Lundey report failed to evaluate what it would take to modify the other wet bottom turbos to reduce NOx emissions to levels as low as Unit 3's emissions.

I have attached a letter to Peter Tsiritogis,US EPA, regarding the acid rain program's proposed NOx rule. Please contact me at (904) 488-1344 or email (COSTELLO_M@DEP.STATE.FL.US) if you need clarification or have questions.

Sincerely,

Martin Costello

Martin Costello, P.E.
Bureau of Air Regulation

cc: Jerry Campbell
Jerry Kissel

Attachment

to: C Phillips from JK 9/11/96

DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT SYSTEM
AIR INDEX REPORT

Owner: TECO AIRS ID: 0570040 Status: A
Compliance Tracking Code: A Title V: Y DFC: 01-SEP-95

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
16	UNIT 4 COAL BUNKER W/ROTO-CLONE	A	AO29250139	20-JUL-94	12-JUL-99
17	UNIT 5 COAL BUNKER W/ROTO-CLONE	A	AO29250139	20-JUL-94	12-JUL-99
18	UNIT 6 COAL BUNKER W/ROTO-CLONE	A	AO29250139	20-JUL-94	12-JUL-99
19	UNIT#4- B&W WET BOTTOM CYCLONIC FIRING COAL FIRED BOILER, WE	I	AO29255208	02-DEC-94	14-OCT-99

Owner: TECO Big Bend AIRS ID: 0570039 Status: A
Compliance Tracking Code: A Title V: Y DFC: 29-AUG-95

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
1	UNIT #1 COAL FIRED BOILER W/ RESEARCH-COTRELL ESP *all AO's except 1 AC copy enclosed*	A	AO29219924	24-NOV-92	01-DEC-97
2	UNIT #2 RILEY-STOKER COAL FIRED BOILER W/ ESP *all AO's*	A	AO29179912	19-NOV-90	18-OCT-95
3	UNIT #3 RILEY-STOKER COAL-FIRED BOILER W/ ESP	A	AO29179911	29-AUG-90	30-AUG-95
4	UNIT #4 COAL-FIRED BOILER W/ BELCO ESP PSD-FL-040 *2 files enclosed - pls return when you're finished (copy parts you need?)*	A			
5	BIG BEND STATION COMBUST. TURBINE #2 - FIRED BY NO. 2 FUEL O *copies of AC's enclosed*	A	AO29174596	14-MAR-90	09-MAR-95
6	GAS TURBINE #3 - WESTINGHOUSE TURBINE FIRED BY NO. 2 FUEL OI	A	AO29174611	08-MAY-90	27-APR-95
7	GAS TURBINE #1 FIRED BY #2 FUEL OIL *all AO's*	A	AO29160257	19-JAN-90	07-JUL-94
8	BIG BEND STATION UNIT NO. 1 & NO. 2 FLY ASH SILO WITH BAGHOU *copy of AC enclosed*	A	AO29160255	19-JAN-90	22-DEC-94
9	FLY-ASH SILO FOR UNIT #3 *all AO's*	A	AO29161082	16-OCT-91	07-JUL-94
10	BIG BEND COAL YARD.PERMITTED UNDER PA79-12 & PSD-FL-040 P *file is out - still searching; there were AC mod's in '92 or so*	A			
11	TRUCK UNLOADING OF LIMESTONE *no files in cabinets - sec'y is tracking them down*	A			
12	LIMESTONE SILO A W/ 2 BAGHOUSES. 1 IS 100% BACK-UP P	A			
13	LIMESTONE SILO B W/ 2 BAGHOUSES. 1 IS 100% BACK-UP P	A			
14	FLYASH SILO FOR UNIT #4 P	A			

Owner: TECO AIRS ID: 0570039 Status: A
Compliance Tracking Code: A Title V: Y DFC: 29-AUG-95

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
15	UNIT 1 COAL BUNKER W/ROTO-CLONE	A	AO29163788	06-OCT-89	30-JUN-94
16	UNIT 2 COAL BUNKER W/ROTO-CLONE	A all AO's	AO29163788	06-OCT-89	30-JUN-94
17	UNIT 3 COAL BUNKER W/ROTO-CLONE	A	AO29163788	06-OCT-89	30-JUN-94
18	BIG BEND STATION UNIT NO. 1 AND NO. 2 OPEN BED TRUCK LOADOUT	A included in unit 08 file	AO29160255	19-JAN-90	22-DEC-94
19	FLY-ASH SILO FOR UNIT #3	A all AO's	AO29161082	16-OCT-91	07-JUL-94

Owner: TERRA VAC CORPORATION AIRS ID: 0570398 Status: I
Compliance Tracking Code: B Title V: N DFC:

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
1	VACUUM EXTRACTION SYSTEM (RENTAL CAR FACILITY)	I			
2	VACUUM EXTRACTION SYSTEM (TANK FARM/TRANSFER LINES)	I			
3	VACUUM EXTRACTION SYSTEM (SOIL TREATMENT CELLS)	I			

Owner: THE DAVID J. JOSEPH COMPANY AIRS ID: 0570446 Status: A
Compliance Tracking Code: B Title V: N DFC:

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
1	SCRAP METAL TRANSFER OPERATION	A	AO29238834	28-JAN-94	31-DEC-98
2	FACILITY GROUNDS OF SCRAP METAL FACILITY	A	AO29238834	28-JAN-94	31-DEC-98

Owner: THE HARDAWAY COMPANY AIRS ID: 0570237 Status: A
Compliance Tracking Code: B Title V: N DFC:

E.U.	Description	St	Permit No	Issued Dt	Expiry Dt
1	CEMENT/FLYASH STORAGE SILO NO.1	A	AO29254305	22-FEB-95	29-FEB-00
2	CEMENT SILO NO 2(EAST)/MERTS MODEL C 250 S.F.BAGHOUSE	A	AO29254305	22-FEB-95	29-FEB-00
3	FLY ASH SILO NO 3	A	AO29254305	22-FEB-95	29-FEB-00
4	CEMENT WEIGH HOPPER AND TRUCK LOADING	A	AO29167052	29-SEP-89	27-SEP-94

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

September 30, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Patrick Ho, P.E.
Manager of Environmental Planning
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

Dear Mr. Ho:

Re: Firing of Coal/Petcoke Blend in Big Bend Unit 3
Amendment of Permit AO29-179911
AIRS I.D. No. 0570039-001-AC

The Department hereby amends the subject Air Operation Permit allowing the firing of a blend of coal and petroleum coke. The existing Air Operation Permit, previously amended on May 12, 1995, is amended as follows:

DESCRIPTION

Change From:

For the operation of a 4115 MMBTU/hr coal fired steam generator designated as Unit No. 3 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. The generator has a nameplate capacity of 445.5 MW. Operation of this unit may include diverting all of the flue gas into the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system. Diversion of the flue gas stream will allow the emissions from this unit to be vented to the Unit 4 FGD system for emission reduction.

Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator manufactured by Research-Cottrell, Inc. Sulfur dioxide emissions will be controlled by diverting the flue gas emissions to the Unit No. 4 FGD system. Sulfur dioxide emissions that are generated and not diverted through the Unit No. 4 FGD system are uncontrolled.

Change To:

For the operation of a 4115 MMBTU/hr steam generator designated as Unit No. 3 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. The generator has a nameplate capacity of 445.5 MW. **This unit may be fired on coal or a coal/petroleum coke blend consisting of a maximum of 20.0 percent petroleum coke by weight.** Operation of this unit may include diverting all of the flue gas into the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system. Diversion of the flue gas stream will allow the emissions from this unit to be vented to the Unit 4 FGD system for emission reduction.

Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator manufactured by Research-Cottrell, Inc. Sulfur dioxide emissions will be controlled by diverting the flue gas emissions to the Unit No. 4 FGD system. Sulfur dioxide emissions that are generated and not diverted through the Unit No. 4 FGD system are uncontrolled.

New Specific Condition 21:

Fuels fired in Unit No. 3 shall consist of coal or a coal/petroleum coke blend containing a maximum of 20.0% petroleum coke by weight. The sulfur content of the petroleum coke shall not exceed 6.0 % by weight (dry basis). Vanadium content of the mineral ash from the petroleum coke fired shall not exceed 35.0% by weight (ignited basis). [Rule 62-4.070(3), F.A.C.]

New Specific Condition 22:

Gravimetric instrument data verifying that the 20.0% maximum petroleum coke content by weight has not been exceeded shall be maintained for two years and submitted to the Department and the Environmental Protection Commission of Hillsborough County (EPCHC) with each annual operating report. Also to be maintained and available for inspection shall be a record of operation showing the date, fuel used, mode of operation (integrated/non-integrated), and the duration of all startups, shutdowns and malfunctions. [Rule 62-4.070(3), F.A.C.]

New Specific Condition 23:

At all times while firing any blend of coal and petroleum coke, Unit No. 3 shall operate only in the integrated mode as described in Specific Condition No. 4 except during startups, shutdowns and/or malfunctions during all of which best operational practices shall be

employed including the cessation of petroleum coke bunkering. The permittee shall maintain and submit to the Department and the EPCHC on an annual basis for a period of 5 years from the date the unit begins firing petroleum coke, data demonstrating that the operational change did not result in an emissions increase. [Rule 62-4.070(3), F.A.C.]

A copy of this amendment letter shall be attached to and shall become a part of Air Operation Permit AO29-179911.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

for Howard L. Rhodes, Director
Division of Air Resources
Management

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960
FAX (813) 272-5157

AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530

WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788

WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

MEMORANDUM

DATE: September 10, 1996

TO: John Brown

FROM: Rick Kirby **THRU:** Jerry Campbell
Iwan Choronenko

SUBJECT: Title V Review of TECO Facilities in Hillsborough County

The EPC has received copies of Tampa Electric Company Title V applications. The packages were received August 14 and 21, 1996 with a request that comments be provided by September 9, 1996. The actual application and some supporting documentation were provided on computer disk.

I have begun my initial review of the Big Bend facility and have already turned up several issues which should be addressed. Some of these are as follows:

1. The State sulfur dioxide standards for the Big Bend and Gannon stations do not appear to meet any of the criteria for practical enforceability. Rules 62-296.405(1)(c)2.a. and b., F.A.C. are truly not comprehensible to anyone other than a doctorate of mathematics or statistics. While we are not suggesting the standard be tightened through the Title V process, we are stating that it should be simplified so it is meaningful. TECO now has CEMs in the stacks and we should look to establishing them as the reference method with a practically enforceable standard that will pass the EPA muster. We do not see how they can provide reasonable assurance that these standards are being met or that these limits protect the ambient air quality standards. You recall we have experienced a number of sulfur dioxide violations downwind of the Gannon Station and these have not been resolved. The EPC feels very strongly about this particular issue.

2. It appears that many sources have been grouped into one emissions unit, when they may not meet the State definition of similar sources. These include fuel and other material handling.

3. Many of these units have been presented as being fugitive emissions sources when they do not meet that definition.

4. There are fuels and chemicals listed for use in boilers which have no previous permitting approval. These include used oil and non-hazardous cleaning chemicals.

5. Some emission units are not listed. EPC had previously agreed to defer permitting of a marine vessel repair and painting operation to be included in the Title V process. It was not found in this package.

Based on the above issues, I feel it is necessary to have EPC permitting engineers perform an inspection of each facility, to include a thorough air pollution source audit, as well as an in depth application and file review. Additionally, EPC has been unable to generate or access the applications for the Hookers Point and F.J. Gannon facilities. As you may be aware, FDEP data personnel came to EPC recently. On the same day, a lightning strike took out a large part of our computer system. It is still not completely functional. Cindy Phillips has graciously agreed to generate hard copies of the two remaining facilities.

I would like to close by saying that these are very complex projects. In addition to the size of each facility, there are complicating factors such as the outstanding Chapter 120 F.S. hearing request by the citizens of Apollo Beach for the latest Big Bend modification and the application for modification at the F.J. Gannon facility which may well trigger PSD. This is the largest polluter in Hillsborough County and a thorough, complete review is called for. We respectfully request that the review time given us be extended for 30 days to insure that we can properly represent the interest of the citizens.

bm

BEST AVAILABLE COPY

Department of Environmental Protection

RECEIVED

AUG 1 1994

ENVIRONMENTAL

Lawton Chiles
Governor

Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

Virginia B. Wetherell
Secretary

96

NOTICE OF PERMIT AMENDMENT

Mr. Patrick A. Ho, P.E.
Manager, Environmental Permitting
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111

Dear Mr. Ho:

Re: Hillsborough County - AP
A029-179911, PATS Processing No. 254096

On July 5, 1994, the Department received your request to amend air pollution permit A029-179911 which is for Big Bend Station Unit No. 3. Specifically, the request related to the recent legislation involving nitrogen oxide compliance limits pursuant to 40 CFR 75. Therefore, as requested permit A029-179911 is hereby amended as follows:

Specific Condition No. 5

From: The nitrogen oxides emission rate (expressed as NO_2) from this source shall not exceed 0.70 pound per million Btu heat input. [Rule 17-2.600(5)(a)4.d., F.A.C.].

To: The nitrogen oxides emission rate (expressed as NO_2) from this source shall not exceed 0.70 pounds per million Btu heat input based upon a 30-day rolling average. [Rule 17-296.405(1)(d)4., F.A.C.]

Specific Condition No. 10

From: This source shall be stack tested for nitrogen oxides (expressed as NO_2) at intervals of 12 months from the date of August 14, 1989, or within a 90 day period prior to that annual date. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

To: This source shall demonstrate compliance for nitrogen oxides (expressed as NO_2) based upon a 30-day rolling average. The methodology to be used will follow the criteria set forth in 40 CFR 60, Subpart Da. the calculations shall be consistent with the equations in 40 CFR 60, Appendix A, Reference Method 19, Section 4.2. (July 1, 1993). Data collected during boiler operating days will be used to calculate the 30-day rolling average except during periods of start-up, shut down, or malfunction, consistent with the provisions of Rule 17-210.700, F.A.C.

For the purpose of calculating a 30-day rolling average, a boiler operating day is defined as a 24-hour period (between 12:01 a.m. and 12:00 midnight) during which fossil fuel is combusted in a steam operating unit for the entire 24-hours.

The continuous emission monitor shall meet the quality assurance requirements and performance specifications contained 40 CFR 75.

A report shall be submitted to both the Florida Department of Environmental Protection and the Environmental Protection Commission of Hillsborough County within 30 days following each calendar quarter. This report shall contain the 30-day rolling average, all time periods of boiler operation as well as a statement of CEM and/or boiler malfunction, start-up or shutdown.

A person whose substantial interests are affected by this permit amendment may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of receipt of this permit amendment. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by Petitioner, if any;

(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or

(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and

(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

This permit amendment is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition and conforms to Rule 17-103.070, F.A.C. Upon timely filing of a petition or a request for an extension of time this permit amendment will not be effective until further Order of the Department.

When the Order (Permit Amendment) is final, any party to the Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate procedure, with the Clerk of the Department in the Office of

General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Final Order is filed with the Clerk of the Department.

This letter must be attached to and becomes a part of permit A029-179911. If you have any questions, please call Mr. Jim McDonald of my staff at (813)744-6100 extension 421.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

For Richard D. Garrity, Ph.D.
Director of District Management

cc: EPCHC

CERTIFICATE OF SERVICE

This is to certify that this NOTICE OF PERMIT AMENDMENT and all copies were mailed by certified mail before the close of business on JUL 29 1994 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGEMENT FILED, on this date, pursuant to Section 120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledge.

(Clerk) JUL 29 1994
(Date)

Florida Department of Environmental Regulation

Southwest District • 4520 Oak Fair Boulevard • Tampa, Florida 33610-7347 • 813-623-5561

Bob Martinez, Governor | Dale Twachtmann, Secretary | John Shearer, Assistant Secretary | Dr. Richard Garrity, Deputy Assistant Secretary

8/30/90

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 & 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans and other documents, attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of a 4115 MMBTU/hr. coal fired steam generator designated as Unit No. 3 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. The generator has a nameplate capacity of 445.5 MW. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator manufactured by Research-Cottrell, Inc.

Location: Big Bend Road, Ruskin

UTM: 17-361.9 E 3075.0 N NEDS NO: 0039 Point ID: 03

Replaces Permit No.: AO29-93937

Extended 8/14/96

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

1. A part of this permit is the attached 15 General Conditions.

2. Except as provided in Specific Condition #6; the particulate matter emission rate for this source shall not exceed 0.1 pound per million Btu heat input, over a two hour average.
[Rule 17-2.600(5)(a)2., F.A.C.].

3. Except as provided in Specific Condition #6; Visible Emissions from this source shall not exceed 20% opacity except for one six-minute period per hour during which opacity shall not exceed 27%.
[Rule 17-2.600(5)(a)1., F.A.C.].

4. Big Bend Station Units 1, 2, and 3, in total, shall not emit more than 31.5 tons per hour of sulfur dioxide on a three hour average, but in no case to exceed a two hour average emission of 6.5 pounds of sulfur dioxide per million Btu heat input. Units 1, 2, and 3, in total, shall not emit more than 25 tons per hour of sulfur dioxide on a 24 hour average. [Rule 17-2.600(5)(a)3.b.(ii), F.A.C.].

5. The nitrogen oxides emission rate (expressed as NO_2) from this source shall not exceed 0.70 pound per million Btu heat input.
[Rule 17-2.600(5)(a)4.d., F.A.C.].

6. A. Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown are permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized. [Rule 17-2.250(2), F.A.C.].

B. Excess emissions resulting from boiler cleaning (soot blowing) and load change are permitted provided that the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not exceed 60% opacity, and providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of the excess emissions are minimized. Visible emissions above 60% opacity are allowed for not more than 4, six-minute periods, during the 3-hour period of excess emissions allowed by part B. of this specific condition. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hour period of excess emissions allowed by part B. of this specific condition. [Rule 17-2.250(3), F.A.C.].

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

7. Excess emissions resulting from malfunctions are permitted providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of excess emissions are minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department of Environmental Regulation for longer duration. [Rule 17-2.250(1), F.A.C.]. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction is prohibited. [Rule 17-2.250(4), F.A.C.]. In case of excess emissions resulting from malfunctions, Tampa Electric Company shall notify the Environmental Protection Commission of Hillsborough County in accordance with Rule 17-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested. [Rule 17-2.250(6), F.A.C.].

8. This source shall be stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions, at intervals of 12 months from the date of August 14, 1989, or within a 90 day period prior to that annual date. A test under sootblowing conditions which demonstrates compliance with a non-sootblowing emission limitation will be accepted as proof of compliance with that non-sootblowing emission limitation. The visible emissions DER Method No. 9 test period for this source shall be at least 60 minutes in duration. Visible emissions testing shall be conducted simultaneously with particulate matter testing unless visible emissions testing is not required. In situations where DER Method 9 visible emissions testing is not possible during particulate matter testing, such as under overcast days, independent visible emissions testing may be performed at a later date within 5 days. Reasons for non-simultaneous testing must be provided in the test report. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

9. This source shall be stack tested for sulfur dioxide at intervals of 12 months from the date of August 14, 1989, or within a 90 day period prior to that annual date. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

10. This source shall be stack tested for nitrogen oxides (expressed as NO_2) at intervals of 12 months from the date of August 14, 1989, or within a 90 day period prior to that annual date. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

11. Compliance testing for particulate matter emissions and visible emissions may be conducted either: (a) without fly ash re-injection occurring, or (b) while fly ash collected by the precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate. If the most recent particulate and visible emissions compliance tests were conducted without fly ash re-injection occurring, and fly ash re-injection occurs for any reason other than a malfunction, then the results from new particulate and visible emissions compliance tests conducted while fly ash collected by the precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate shall be submitted to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County within 60 days of the date that such fly ash re-injection occurred. The Department of Environmental Regulation or the Environmental Protection Commission of Hillsborough County may, for good cause shown, grant an extension of the 60 day time limit on a case by case basis. [Rule 17-4.070(3), F.A.C.].

12. Compliance with the SO2 emission standards set forth by Specific Condition #4 shall be demonstrated by:

A. Conducting an annual stack test, using an approved DER Method, with a fuel analysis for the coal burned to show compliance with the two hour standard of 6.5 pounds of sulfur dioxide per million Btu heat input.

B. Not charging the fuel bunkers of units 1 through 3 with any coal with a composite sulfur content that would produce emissions greater than 6.5 pounds of sulfur dioxide per million Btu heat input to show continuing compliance with the two hour standard. This can be accomplished in part by blending various grades of coal on-site prior to charging into the fuel bunkers located in the tripper room.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

C. Daily composite fuel sampling and analysis to show compliance with the emission cap for units 1 through 3 of 25 tons of sulfur dioxide per hour on a 24 hour average. The following equation shall be used:

$$SO_2 = \underset{(i)}{\frac{\#S}{MMBTU}} \times \underset{(ii)}{\frac{2\ \#SO2}{\#S}} \times \underset{(iii)}{\frac{MMBTU}{MWH}} \times \underset{(iv)}{.95} \times \underset{(v)}{\frac{MWH}{day}} \times \underset{(vi)}{\frac{tons\ SO2}{2000\ lbs.\ SO2}}$$

Where: (i) - comes from the daily fuel analysis
(ii) - conversion factor
(iii)- heat rate from the previous month heat rate calculation
(iv) - Conversion factor describing percent S in the coal that is converted to gaseous SO2 (reference 6/25/76 DER-TECO Stipulation)
(v) - daily generation from station logs
(vi) - conversion factor

This equation shall be used and the calculations completed for each of the units 1 through 3. This information shall be submitted to the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation on a quarterly basis no later than 45 days following the calendar quarter. If an exceedance of this standard occurs, then the permittee shall report this event to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County within 24 hours of the determination.

D. Adhering to the study, previously submitted, that demonstrates by statistical analysis, that the 31.5 tons of SO2 per hour on a three hour average is being met. This study provides reasonable assurance that a daily sample can be used to demonstrate compliance with the 3 hour emission cap.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

13. The maximum permitted heat input rate for this source is 4,115 million Btu per hour. Approved compliance testing of emissions shall be conducted within ±10% of the maximum permitted heat input rate, when practicable. Testing may be conducted at less than 90% of the maximum permitted heat input rate; however, if so, the maximum permitted heat input rate is automatically amended to be equal to the test heat input rate. If the maximum permitted heat input rate for this source is exceeded by more than 10%, compliance testing shall be performed within 60 days of initiation of the higher rate and the results of the tests shall be submitted to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County. The Department of Environmental Regulation or the Environmental Protection Commission of Hillsborough County may, for good cause shown, grant an extension of the 60 day time limit on a case by case basis. Acceptance of said test will automatically amend the maximum permitted heat input rate to be equal to the test heat input rate. Emission limitations are not automatically adjusted above the allowable levels established by the permit and/or the design process rate. The actual heat input rate shall be specified in each test report. Failure to submit the actual heat input rate, or operation at conditions during testing which do not reflect normal operating conditions may invalidate the test and fail to provide reasonable assurance of compliance. [Rule 17-4.070(3), F.A.C.].

14. Tampa Electric Company shall notify the Environmental Protection Commission of Hillsborough County at least 15 days prior to the date on which each formal compliance test is to begin of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner. The Environmental Protection Commission of Hillsborough County may waive the 15 day notice requirement on a case by case basis. [Rule 17-2.700(2)(a)9., F.A.C.].

15. A continuous monitoring system to determine in-stack opacity from this source shall be calibrated, operated and maintained in accordance with Rule 17-2.710(1), F.A.C.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179911
County: Hillsborough
Expiration Date: 08/30/95
Project: Big Bend Station
Unit No. 3

SPECIFIC CONDITIONS:

16. A report shall be submitted to both the Florida Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County within 30 days following each calendar quarter detailing excess opacity readings recorded during the three month period. For the purpose of this report, excess emissions shall be defined as all six minute averages of opacity which exceed the limitations of specific conditions #3 and #6. The information supplied in this report shall be consistent with the reporting requirements of 40 CFR 51 Appendix P [Rule 17-2.710(1), F.A.C.].

17. Submit for this facility, each calendar year, on or before March 1, an emission report for the preceding calendar year containing the following information pursuant to Subsection 403.061(13), Florida Statutes:

(A) Annual amount of materials and/or fuels utilized.
(B) Annual emissions (note calculation basis).
(C) Any changes in the information contained in the permit application.

The Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation shall each receive a copy of this report.

18. Issuance of this permit does not relieve the permittee from complying with applicable emission limiting standards or other requirements of Chapter 17-2, or any other requirements under federal, state, or local law. [Rule 17-2.210, F.A.C.]

19. Four applications to renew this operating permit shall be submitted to the Environmental Protection Commission of Hillsborough County by July 1, 1995. [Rules 17-4.050(2) and 17-4.090(1), F.A.C.].

Issued this 29 day of
August, 1990.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

For Dr. Richard D. Garrity
Deputy Assistant Secretary

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Lawton Chiles
Governor

Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619

Virginia B. Wetherell
Secretary

NOTICE OF PERMIT AMENDMENT

CERTIFIED MAIL

Mr. Patrick A. Ho, P.E.
Manager, Environmental Planning
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601 /

Dear Mr. Ho:

Re: Permit Amendment Request Received 03/16/95
Big Bend Unit No. 3
PATS Processing No. AO29-269732
Current DEP File No. AO29-179911

On 03/16/95 the Department received your request for an amendment to air operating permit No. AO29-179911. Therefore, the following amendment is hereby made in the permit:

DESCRIPTION

Change from:

For the operation of a 4115 MMBTU/hr. coal fired steam generator designated as Unit No. 3 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. The generator has a nameplate capacity of 445.5 MW. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator manufactured by Research-Cottrell, Inc.

Change to:

For the operation of a 4115 MMBTU/hr. coal fired steam generator designated as Unit No. 3 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. The generator has a nameplate capacity of 445.5 MW. **Operation of this unit may include diverting all of the flue gas into the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system. Diversion of the flue gas stream will allow the emissions from this unit to be vented to the Unit 4 FGD system for emission reduction.**

Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Research-Cottrell, Inc. **Sulfur dioxide emissions will be controlled by diverting the flue gas emissions to**

the Unit No. 4 FGD system. Sulfur dioxide emissions that are generated and not diverted through the Unit No. 4 FGD system are uncontrolled.

Specific Condition No. 4:

Nonintegrated Operation Sulfur Dioxide Emission Limits:

4. Big Bend Station Units No. 1, 2, and 3 in total shall not emit more than 31.5 tons per hour of sulfur dioxide on a three hour average, but in no case to exceed a two hour average emission of 6.5 pounds of sulfur dioxide per million Btu heat input. Units 1, 2, and 3, in total, shall not emit more than 25 tons per hour of sulfur dioxide on a 24 hour average (Rule 62-296.405(1)(c)2, F.A.C.).

Integrated Operation Sulfur Dioxide Emission Limits:

Tampa Electric Company is allowed to divert and integrate all of Big Bend Unit No. 3 flue gas for purposes of treating that flue gas in the existing Big Bend Unit No. 4 flue gas desulfurization (FGD) system. While in the integrated mode Units No. 3 and 4 shall meet the sulfur dioxide emission limitations that are applicable to Unit No. 4 (40 CFR 60.40a and Permit No. PSD-FL-040).

Add Specific Condition No. 20:

20. All Specific Conditions that reference testing requirements (Nos. 8,9,10,11, and 12) apply to operation in the nonintegrated mode. Testing as referenced in the operating permit should be conducted under nonintegrated conditions (i.e., no diversion of flue gas emissions is allowed during compliance testing).

A person whose substantial interests are affected by this permit amendment may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 within 14 days of receipt of this permit amendment. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative proceeding (hearing) under Section 120.57, Florida Statutes.

The petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department's Permit File Number and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's subsequent interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action of proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this permit amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the permit amendment have a right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this permit amendment, in the Office of General Counsel at the above address of the Department. Failure to petition within the allotted time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, Florida Statutes, and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 62-5.207, Florida Administrative Code.

This permit amendment is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for an extension of time in which to file a petition is filed within the time specified for filing a petition and conforms to Rule 17-103.070, Florida Administrative Code. Upon timely filling of a petition or a request for an extension of time this permit amendment will not be effective until further Order of the Department.

When the Order (Permit Amendment) is final, any party to the Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellant Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate district Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Final Order is filed with the Clerk of the Department.

This amendment letter must be attached to and becomes a part of air operation permit number AO29-179911. If you have any questions, please contact George Richardson in the Air Permitting Section at (813)744-6100, Ext. 105.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

For Dr. Richard D. Garrity, Ph.D.
Director of District Management
Southwest District

3804 Coconut Palm Drive
Tampa, FL 33619-8318
(813)744-6100

cc: J. Reynolds, DEP
EPCHC

CERTIFICATE OF SERVICE

The undersigned duly designated Deputy Department Clerk hereby certifies that this Notice of Permit Amendment and all copies were mailed by certified mail before the close of business on MAY 12 1995 to the listed persons.

FILING AND ACKNOWLEDGEMENT

FILED, on this date, pursuant to Paragraph 120.52(11), Florida Statutes, with the designated Deputy Department Clerk, receipt of which is hereby acknowledged.

Marilyn Quispe
Clerk

MAY 12 1995
Date

Florida Department of Environmental Regulation

Southwest District • 4520 Oak Fair Boulevard • Tampa, Florida 33610-7347 • 813-623-5561

Bob Martinez, Governor | Dale Twachtmann, Secretary | John Shearer, Assistant Secretary | Dr. Richard Garrity, Deputy Assistant Secretary

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

Issued 11/19/90

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 & 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans and other documents, attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of a 3,996 MM Btu/hr. coal fired steam generator designated as Unit No. 2 at the Big Bend Station. This "wet" bottom boiler was manufactured by Riley-Stoker and is an opposed-fired turbo boiler. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator manufactured by Western Precipitator, Division, Joy Manufacturing Corporation.

Location: Big Bend Road, Ruskin

UTM: 17-361.9 E 3075.0 N NEDS NO: 0039 Point ID: 02

Replaces Permit No.: AO29-66329

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

1. A part of this permit is the attached 15 General Conditions.

2. Except as provided in specific condition #5; the particulate matter emission rate for this source shall not exceed 0.1 pound per million Btu heat input, over a two hour average. [Rule 17-2.600(5)(a)2., F.A.C.].

3. Except as provided in specific condition #5; visible emissions from this source shall not exceed 20% opacity except for one six-minute period per hour during which opacity shall not exceed 27%. [Rule 17-2.600(5)(a)1., F.A.C.].

4. Big Bend Station Units 1, 2, and 3, in total, shall not emit more than 31.5 tons per hour of sulfur dioxide on a three hour average, but in no case to exceed a two hour average emission of 6.5 pounds of sulfur dioxide per million Btu heat input. Units 1, 2, and 3, in total, shall not emit more than 25 tons per hour of sulfur dioxide on a 24 hour average. [Rule 17-2.600(5)(a)3.b.(ii), F.A.C.].

5. Excess Emissions:

A. Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown are permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized. [Rule 17-2.250(2), F.A.C.].

B. Excess emissions resulting from boiler cleaning (soot blowing) and load change are permitted provided that the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not exceed 60% opacity, and providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of the excess emissions are minimized. Visible emissions above 60% opacity are allowed for not more than 4, six-minute periods, during the 3-hour period of excess emissions allowed by part B. of this specific condition. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hour period of excess emissions allowed by part B. of this specific condition. [Rule 17-2.250(3), F.A.C.].

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

C. Excess emissions resulting from malfunctions* are permitted providing (a) best operational practices to minimize emissions are adhered to and (b) the duration of excess emissions are minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department of Environmental Regulation for longer duration. [Rule 17-2.250(1), F.A.C.].

D. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction is prohibited. [Rule 17-2.250(4), F.A.C.].

* In case of excess emissions resulting from malfunctions, Tampa Electric Company shall notify the Environmental Protection Commission of Hillsborough County in accordance with Rule 17-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested. [Rule 17-2.250(6), F.A.C.].

6. This source shall be stack tested for particulate matter and visible emissions, under both sootblowing and non-sootblowing operation conditions, at intervals of 12 months from the date of December 31, 1990, or within a 90 day period prior to that annual date. A test under sootblowing conditions which demonstrates compliance with a non-sootblowing emission limitation will be accepted as proof of compliance with that non-sootblowing emission limitation. The visible emissions DER Method No. 9 test period for this source shall be at least 60 minutes in duration. Visible emissions testing shall be conducted simultaneously with particulate matter testing unless visible emissions testing is not required. In situations where DER Method No. 9 visible emissions testing is not possible during particulate matter testing, such as under overcast days, independent visible emissions testing may be performed at a later date within but not more than 5 days. Reasons for non-simultaneous testing must be provided in the test report. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

7. This source shall be stack tested for sulfur dioxide at intervals of 12 months from the date of December 31, 1990, or within a 90 day period prior to that annual date. Testing procedures shall be consistent with the requirements of Rule 17-2.700, F.A.C. A copy of the test data shall be submitted to both the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation within 45 days of such testing.

8. Compliance testing for particulate matter emissions and visible emissions may be conducted either: (a) without fly ash re-injection occurring, or (b) while fly ash collected by the precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate. If the most recent particulate and visible emissions compliance tests were conducted without fly ash re-injection occurring, and fly ash re-injection occurs for any reason other than a malfunction, then the results from new particulate and visible emissions compliance tests conducted while fly ash collected by the precipitator is being re-injected into the boiler at a rate which is representative of the maximum anticipated fly ash re-injection rate shall be submitted to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County within 60 days of the date that such fly ash re-injection occurred. The Environmental Protection Commission of Hillsborough County may, for good cause shown, grant an extension of the 60 day time limit on a case by case basis.
[Rule 17-4.070(3), F.A.C.].

9. Compliance with the SO_2 emission standards set forth by Specific Condition #4 shall be demonstrated by:

A. Conducting an annual stack test, using an approved DER Method, with a fuel analysis for the coal burned to show compliance with the two hour standard of 6.5 pounds of sulfur dioxide per million Btu heat input.

B. Not charging the fuel bunkers of units 1 through 3 with any coal with a composite sulfur content that would produce emissions greater than 6.5 pounds of sulfur dioxide per million Btu heat input to show continuing compliance with the two hour standard. This can be accomplished in part by blending various grades of coal on-site prior to charging into the fuel bunkers located in the tripper room.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

C. Daily composite fuel sampling and analysis to show compliance with the emission cap for units 1 through 3 of 25 tons of sulfur dioxide per hour on a 24 hour average. The following equation shall be used:

$$\begin{array}{ccccccccccc} & & (i) & & (ii) & & (iii) & & (iv) & & (v) & & (vi) \\ SO_2 & = & \frac{\#S}{MMBTU} & X & \frac{2\ \#SO2}{\#S} & X & \frac{MMBTU}{MWH} & X & .95 & X & \frac{MWH}{day} & X & \frac{tons\ SO2}{2000\ lbs.\ SO2} \end{array}$$

Where: (i) - comes from the daily fuel analysis
(ii) - conversion factor
(iii) - heat rate from the previous month heat rate calculation
(iv) - conversion factor describing percent S in the coal that is converted to gaseous SO2 (reference 6/25/76 DER-TECO stipulation)
(v) - daily generation from station logs
(vi) - conversion factor

This equation shall be used and the calculations completed for each of the units 1 through 3. This information shall be submitted to the Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation on a quarterly basis no later than 45 days following the calendar quarter. If an exceedance of this standard occurs, then the permittee shall report this event to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County within 24 hours of the determination.

D. Adhering to the study, previously submitted, that demonstrates by statistical analysis, that the 31.5 tons of SO2 per hour on a three hour average is being met. This study provides reasonable assurance that a daily sample can be used to demonstrate compliance with the 3 hour emission cap.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: AO29-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

10. The maximum permitted heat input rate for this source is 3,996 million Btu per hour. Approved compliance testing of emissions shall be conducted within ±10% of the maximum permitted heat input rate, when practicable. Testing may be conducted at less than 90% of the maximum permitted heat input rate; however, if so, the maximum permitted heat input rate is automatically amended to be equal to the test heat input rate. If the maximum permitted heat input rate for this source is exceeded by more than 10%, compliance testing shall be performed within 60 days of initiation of the higher rate and the results of the tests shall be submitted to the Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County. The Environmental Protection Commission of Hillsborough County may, for good cause shown, grant an extension of the 60 day time limit on a case by case basis. Acceptance of said test will automatically amend the maximum permitted heat input rate to be equal to the test heat input rate. Emission limitations are not automatically adjusted above the allowable levels established by the permit and/or the design process rate. The actual heat input rate shall be specified in each test report. Failure to submit the actual heat input rate, or operation at conditions during testing which do not reflect normal operating conditions may invalidate the test and fail to provide reasonable assurance of compliance. [Rule 17-4.070(3), F.A.C.].

11. Tampa Electric Company shall notify the Environmental Protection Commission of Hillsborough County at least 15 days prior to the date on which each formal compliance test is to begin of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner. The Environmental Protection Commission of Hillsborough County may waive the 15 day notice requirement on a case by case basis. [Rule 17-2.700(2)(a)9., F.A.C.].

12. A continuous monitoring system to determine in-stack opacity from this source shall be calibrated, operated and maintained in accordance with Rule 17-2.710(1), F.A.C.

PERMITTEE:
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601

PERMIT/CERTIFICATION
Permit No: A029-179912
County: Hillsborough
Expiration Date: 11/21/95
Project: Big Bend Station
Unit No. 2

SPECIFIC CONDITIONS:

13. Tampa Electric Company shall submit to both the Florida Department of Environmental Regulation and the Environmental Protection Commission of Hillsborough County a written report of emissions in excess of the emission limiting standards as set forth in Rule 17-2.600(5) for each calendar quarter. The nature and cause of the excessive emissions shall be explained. This report does not relieve Tampa Electric Company of the legal liability for violations. All recorded data shall be maintained on file for a period of at least 2 years. The information supplied in this report shall be consistent with the reporting requirements of 40 CFR 51 Appendix P. The report shall be submitted within 30 days following each calendar quarter. [Rules 17-2.710(1), 17-2.710(2), and 17-4.070(3), F.A.C.].

14. Submit for this facility, each calendar year, on or before March 1, an emission report for the preceding calendar year containing the following information pursuant to Subsection 403.061(13), Florida Statutes:

(A) Annual amount of materials and/or fuels utilized.
(B) Annual emissions (note calculation basis).
(C) Any changes in the information contained in the permit application.

The Environmental Protection Commission of Hillsborough County and the Florida Department of Environmental Regulation shall each receive a copy of this report.

15. Issuance of this permit does not relieve the permittee from complying with applicable emission limiting standards or other requirements of Chapter 17-2, or any other requirements under federal, state, or local law. [Rule 17-2.210, F.A.C.].

16. Four applications to renew this operating permit shall be submitted to the Environmental Protection Commission of Hillsborough County by September 22, 1995.
[Rules 17-4.050(2) and 17-4.090(1), F.A.C.].

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

for J. Harry Kerns
Dr. Richard D. Garrity
Deputy Assistant Secretary

ENVIRONMENTAL PROTECTION COMMISSION
HILLSBOROUGH COUNTY

ADMINISTRATIVE OFFICES, LEGAL & WATER MANAGEMENT DIVISION
1900 - 9TH AVENUE
TAMPA, FLORIDA 33605
TELEPHONE (813) 272-5960
FAX (813) 272-5157

AIR MANAGEMENT DIVISION
TELEPHONE (813) 272-5530
WASTE MANAGEMENT DIVISION
TELEPHONE (813) 272-5788
WETLANDS MANAGEMENT DIVISION
TELEPHONE (813) 272-7104

RECEIVED
OCT 2 1996
BUREAU OF
AIR REGULATION

MEMORANDUM

DATE: September 30, 1996

TO: John Brown, P.E., FDEP

FROM: RK Richard C. Kirby, IV, P.E. THRU: Jerry Campbell, P.E.

SUBJECT: Tampa Electric Company, Big Bend Station Title V

The referenced application has been reviewed by EPC engineering staff. A facility inspection was performed on September 16, 1996. Marty Costello of your office was present during most of the inspection. Based on our review and inspection offer the following comments:

1. The sulfur dioxide standards for Units #1, 2, and 3 in Rule 62-296.405(1)(c)2.b., F.A.C., are not practically enforceable. The multiple standards refer to a group limit of 31.5 TPH on a 3-hour average not to exceed a 6.5 pounds per MMBTU over two hours, and finally a 25 TPH limitation on all three units for a 24-hour average. There is no reasonable way for our inspectors to determine compliance with the convoluted standards, and consequently they would fail any PTE or practically enforceable test. We acknowledge these are in the SIP and did somehow get approved by the EPA over a decade ago. Criteria for standards was different then and we believe Title V anticipated this type of cleanup. We also understand that Title V is not a program for promulgating new standards. However, because these standards are unenforceable and can not be put in a Title V permit, we strongly recommend that they be converted (not strengthened or weakened) to an enforceable form. Since all these units have CEMs, perhaps we should look for a pound per MMBTU over a set averaging time as reported by their continuous instrumentation. TECO Could drop the less effective annual stack testing and fuel sampling programs, and the public would be better protected.

2. On June 6, 1994, during an EPC inspection, a ship repair facility (GC Services, a TECO Transport Company) was found operating along side the Big Bend Station coal yard. TECO previously provided information regarding this operation

following an inspection done on December 6, 1994. During that inspection, EPC was informed that the operations would be included in the Title V application and permit for the power plant. That information is not included.

3. TECO should make a statement of the method(s) used for demonstration compliance for each applicable rule requirement per 40 CFR 70.5(c)(9)ii and Rule 62-213.420(3)(g).

4. 40 CFR 75 requires CEM data to be reported quarterly to the Administrator (EPA). Since EPC is the lead agency in determining compliance, we request that this same data be supplied to our office.

5. TECO has requested that compliance with emissions limits be demonstrated through CEM data or fuel analyses, and that this take the place of stack testing. EPC supports the use of CEMs for compliance demonstration. We do not have the same comfort level with fuel sampling. This is based on the variable nature of fuels, i.e., coal from multiple sources, and pet coke. In addition, we do not have a method for auditing fuel sampling, therefore we do not have assurance on fuel analysis testing.

6. TECO has classified fuel handling as one emission unit. They are currently trying several alternate fuels at their facilities. These will have different potential emissions. Because of this, it is important to differentiate between the different solid fuels. There should be a throughput limitation based on the type of fuel and supporting calculations. The coal headed for the Polk County facility should be included as well.

7. During our inspection, significant fugitive emissions were observed coming from Big Bend #2 furnace. TECO should explain corrective actions and provide a maintenance plan to address fugitives from this unit as well as the other three in the future.

8. TECO is currently adding ammonia and SO_3 to flue gases. These processes should be thoroughly explained and the effects on emissions quantified.

9. TECO uses molten sulfur to generate SO_3 for flue gas conditioning. They should fully describe the storage, process, and units, quantify emissions, and explain why no permit was obtained prior to installation of the system.

10. Multiple emission points are grouped as a single emission unit in the application for some operations (i.e., coal yard, gypsum handling, etc.). Since each emission point will require testing it is to our advantage and TECO's to list each

emission point separately as an emission unit. Our current record keeping system, ARMS, allows input of a certain test only once per emission unit. For example, we would only be able to enter one Method 9 for the coal yard when there are multiple drop points requiring testing. From TECO's standpoint a VE violation at one drop point would put the entire coal yard in violation if it is listed as one unit. It should also be noted that the emission units, as grouped by TECO in the application, do not match the units currently listed in ARMS.

11. Rule 1-3.63(c), Rules of the Environmental Protection Commission of Hillsborough County limits emissions from fossil fuel steam generators to 1.1 pound SO_2 per million Btu heat input when liquid fuel is burned. Since the application includes the burning of used oil and non-hazardous boiler chemical cleaning waste. TECO should provide assurance that the above standard will be met while burning these liquid fuels.

bm

BEST AVAILABLE COPY

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE: TAMPA ELECTRIC COMPANY BIG BEND STATION UNIT 4 MODIFICATION OF CONDITIONS OF CERTIFICATION PA 79-12 HILLSBOROUGH COUNTY, FLORIDA	DEP CASE NO. PA 79-12D OGC CASE NO. 94-0914

FINAL ORDER MODIFYING
CONDITIONS OF CERTIFICATION

On August 17, 1981, the Governor and Cabinet, sitting as the Siting Board, issued a final order approving certification for Tampa Electric Company's (TECO's) Big Bend Station Unit 4. That certification order approved the construction and operation of a 486 MW (gross) coal-fired facility and associated facilities located in Hillsborough County, Florida.

On January 30, 1995 and March 6, 1995, TECO filed a request to modify the conditions of certification pursuant to Section 403.516(1)(b), Florida Statutes. TECO requested that the conditions be modified to approve changes to the Conditions of Certification for the continuous emission requirements necessary to implement in plant modification of flue gas treatment systems and operation. These proposed changes allow treatment of flue gas from Unit 3 in the Unit 4 FGD scrubbers.

Copies of TECO's proposed modification were distributed to all parties to the certification proceeding and made available for public review. On April 7, 1995, Notice of Proposed Modification of power plant certification was published in the Florida Administrative Weekly. As of April 3, 1995, all parties to the original proceeding had received copies of the intent to modify. The notice specified that a hearing would be held if a party to the original certification hearing objects within 45 days from receipt of the proposed notice of modification or if a person whose substantial interests will be affected by the proposed modification objects in writing within 30 days after issuance of the public notice. Written objections to the proposed modifications were not received by the Department. Accordingly, in the absence of any timely objection,

IT IS ORDERED:

The proposed changes to TECO Big Bend Station as described in the January 30, 1995, and March 6, 1995, requests for modification are APPROVED. Pursuant to Section 403.516(1)(b), F.S., the conditions of certification for the TECO Big Bend Station are MODIFIED as follows:

Condition I.B. Air Monitoring Program

1. The permittee shall install and operate continuous~~ly~~ monitoring devices for the Unit 4 boiler exhausts for sulfur dioxide, nitrogen dioxide, oxygen and/or carbon dioxide, and opacity. The monitoring devices shall meet the applicable requirements of Section ~~17-2.08, FAC~~ 62-214, F.A.C., 40 CFR 60.47a., and 40 CFR 75. The opacity monitor shall be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

B.19

B.17

a. When Units 3 and 4 are operating in the integrated mode (Unit 3 flue gases routed through the Unit 4 FGD system), the continuous monitoring system will measure sulfur dioxide emissions at the inlet and outlet of the Unit 4 FGD system and from the Unit 3 stack, while emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.

b. When Units 3 and 4 are not operating in the integrated mode, the continuous monitoring system will measure only Unit 4's inlet duct and stack for SO_2 emissions. The emissions of nitrogen oxides, oxygen and/or carbon dioxide, and opacity shall be measured in the Unit 4 duct prior to the FGD system.

Any party to this Notice has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department of Environmental Protection in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date that the Final Order is filed with the Department of Environmental Protection.

DONE AND ENTERED this 19th day of June, 1995 in Tallahassee, Florida.

STATE OF FLORIDA, DEPARTMENT OF ENVIRONMENTAL PROTECTION

for Kenneth J. Plante
VIRGINIA B. WETHERELL
SECRETARY
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Rebecca Brown 6/19/95
Deputy **Clerk** **Date**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was sent by U.S. Mail to the following this 19th day of June, 1995.

Lawrence N. Curtin, Esq.
Holland & Knight
P.O. Drawer 810
Tallahassee, FL 32302

Martin D. Hernandez, Esq.
Southwest Florida Water
Management District
2379 Broad Street
Brooksville, FL 34609-6899

Michael Palecki
Division of Legal Services
Public Service Commission
101 East Gaines Street
Fletcher Building, Room 212
Tallahassee, FL 32399-0850

Karen Brodeen, Esq.
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

Greg Nelson, P.E.
Tampa, Electric Company
P.O. Box 111
Tampa, FL 33601-0111

Sara M. Fotopulos, Esq.
Environmental Protection
Comm. of Hillsborough Co.
1900 Ninth Avenue
Tampa, FL 33605

Charles T. "Chip" Collette
Department of Environmental
Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 488-9314

Attorney for the Department

Florida Department of
Environmental Protection

Memorandum

done 3/19/96 Cindy

TO: Howard Rhodes

THROUGH: Clair Fancy
A. A. Linero

FROM: Cleve Holladay

DATE: March 19, 1996

SUBJECT: Florida Power Corporation Crystal River Salt Drift Study, PA 77-09, PSD-FL-007

Attached for your review and signature is a letter approving the discontinuation of the FPC Crystal River salt drift monitoring study. This study was required in the original PSD permit for Crystal River Units No. 4 and 5 to monitor the impacts of the cooling towers associated with these units. Fourteen years of monitoring data have been collected and analyzed by FPC. The specific condition requiring this study also provides for its reduction or elimination if no significant impacts are occurring to the surrounding area due to salt drift from these cooling towers. Based on the information provided by FPC and a site visit conducted by department personnel on January 23, 1996, it appears that this condition has been satisfied.

I recommend your approval and signature.

CHF/ch/h

Cindy - Here is an example of how I handle a monitoring condition. If the monitoring seems to be a permanent requirement, then a PSD modification is in order. That shouldn't be too difficult. I would hate not to issue a new "AC" or "PSD" to remove a condition. AL

BEST AVAILABLE COPY

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

March 20, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue, Director
Environmental Services Department H2G
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Re: Crystal River Salt Drift Study
PA 77-09, PSD-FL-007

Dear Mr. Pardue:

The Department has reviewed the recent status reports and your requests to discontinue the salt drift impact study in the vicinity of the Florida Power Corporation (FPC) Crystal River Power Plant. Based on the information provided to the Department and the site visit conducted by department personnel on January 23, the Department has concluded that damage to nearby vegetation has occurred primarily due to natural phenomena rather than by salt drift from the plant.

The Department considers Specific Condition 5 (Ambient Monitoring) of the PSD permit modification dated November 30, 1988 to have been fulfilled. In accordance with Specific Condition 5.c., the Department approves the elimination of the monitoring program contingent on no objections in the next thirty days from EPA. Please note that the plant is still required to monitor particulate matter from the cooling towers.

We have supplied EPA with a copy of all the correspondence related to this intended action. Please note that the authority to eliminate the program applies only to the PSD permit and not to the Site Certification. The parties to the original certification were advised directly and through the notice published in the Florida Administrative Weekly of FPC's request.

If you have any questions regarding this matter, please call Mr. Cleve Holladay at (904)488-1344 or Trudie Bell at (904)921-9886.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/aal/l

cc: Winston Smith, EPA
John Bunyak, NPS
Hamilton Oven, DEP
Trudie Bell, DEP
Bill Thomas, SWD

Memorandum

Florida Department of Environmental Protection

TO: C. H. Fancy, P.E.
A. A. Linero, P.E.

FROM: Ed Svec

DATE: February 16, 1996

SUBJECT: Municipal Solid Waste Landfills - Summary of Subpart Cc and NSPS Subpart WWW

Subpart Cc - Municipal Solid Waste Landfills - Emission Guidelines and Compliance Times

A municipal solid waste (MSW) landfill is defined as the entire disposal facility in a contiguous space where household waste is placed in or on the land. The landfill may also accept other types of RCRA Subtitle D waste, be privately or publicly owned and separated by access roads. The existing facilities have commenced construction/reconstruction/modification before May 30, 1991.. However, any changes to the MSW landfill solely to comply with emission guidelines to these facilities are not considered a modification or reconstruction and will not subject the facility to Subpart WWW.

Emission Guidelines The MSW landfill must have accepted waste anytime since 11/8/87 or have additional capacity, have a design capacity of 2.5 million megagrams (Mg) or 2.5 million cubic meters, and a non-methane organic compound (NMOC) emission rate of greater than or equal to 50 Mg / yr. to be subject to the emission guidelines. If subject to the guidelines, a collection and control system must be installed . The control can be an open flare, a 98% by weight reduction of the NMOC or an enclosed combustor not exceeding 20 ppm as hexane by volume on a dry basis at 3% oxygen at its discharge.

Compliance Times Planning, awarding contracts and installation of the collection and control equipment must begin within 30 months after the effective date of the state emission standards. If the facility is below 50 mg/yr. NMOC on the effective date, installation must begin within 30 months after the date where NMOC equal or exceed 50 Mg/yr.

Subpart WWW - Standards for Air Emissions From Municipal Solid Waste Landfills

MSW landfills which have a capacity less than 2.5 million Mg or 2.5 million cubic meters shall submit an initial design capacity report. If they are not a major source for Part 70 or located at a major source, they are not subject to the standard and do not require permitting under Part 70. If the landfill increases size, an amended design capacity report must be submitted. Landfills with capacities greater than or equal to 2.5 million Mg or cubic meters are subject to Part 70 permitting and must calculate their NMOC emission rate annually.

If the NMOC emission rate is less than 50 Mg/yr., an annual emissions report is submitted and the NMOC rate is recalculated annually until it is either greater than or equal to 50 Mg/yr. or the landfill is closed.

If the NMOC rate is greater than or equal to 50 Mg/yr., a collection and control system must be installed. The system design plan must be submitted within one year. System installation must begin within 18 months of the design plan submittal. The collection system can be either active (requires fans or blowers to remove the gas) or passive (relies on the pressure in the cell to move the gas). Control can be a flare, a device which reduces the mass 98% by weight or an enclosed combustion device which reduces the mass by 98% or 2 ppm volume dry basis at 3% oxygen. If the gas is collected for resale or reuse, all vent emissions must comply with these standards.

The system can be capped or removed when the landfill no longer accepts waste and is permanently closed, the collection and control system has operated a minimum of 15 years and the NMOC rate is less than 50 Mg/yr. on three successive test dates no less than 90 or more than 180 days apart.

Operational Standards For Collection and Control Systems   A collection and control system will be operated for areas or cells with waste placed for 5 or more years if active or 2 or more years if closed or at final grade. The collection system will be operated under negative pressure at the well heads. Well heads in the interior of the cell or area will be operated at gas temperatures below 55°C and extracted gases having either nitrogen less than 20% or oxygen less than or equal to 5%. The collection system will be operated such that methane levels are below 500 ppm around the perimeter of the collection area. All collected gas is to be vented to the control system and the control system is to be operated at all times collected gas is routed to it.

Test Methods and Procedures   Formulas are provided to calculate the NMOC emission rate. The two formulas are for either known or unknown waste acceptance rates and non-degradables can be subtracted if documentation is provided. Tier 1 compares the result of the equation with the standard. If the result is less than 50 Mg/yr., submit an emissions report and recalculate annually. If greater than or equal to 50 MG/yr., install the collection and control system as prescribed or go to Tier 2.

Tier 2 determines the actual NMOC concentration in the landfill. Two probes are installed per hectare and two samples are collected from every probe. Samples are analyzed using Method 25C or Method 18. The average concentration is substituted for the default value in the equation and the NMOC rate is recalculated. If the value is greater than or equal to 50 Mg/yr., install the collection and control system or go to Tier 3. If not, submit the emission rate report and retest the site specific NMOC concentrations every five years.

In Tier 3 a site specific methane generation rate is determined using Method 2E and the previously collected samples. Substitute this value for the default value in the formulas and recalculate. If greater than or equal to 50 Mg/yr. NMOC, install the collection and control system. If less than 50, submit the emission report and recalculate annually. The methane test is performed once and this value is used in all future calculations.

Another equation is provided to calculate the NMOC emission rate after the collection and control system is installed. This equation is used to determine when the system can be removed. The NMOC emission rate will be compared to the PSD major source and significance levels. If controlled, the post installation equation is used.

Performance tests using Method 25 or Method 18 are used to determine the 98% reduction or 20 ppm requirements. An additional equation is provided to calculate efficiency.

<u>Compliance Provisions</u> Equations are provided to calculate the maximum gas flow rate. Using this flow rate, the collection system must be designed to extract and control gas from all portions of the landfill. This is accomplished by keeping a negative pressure at the well heads (gauged monthly). If negative pressure cannot be maintained without air infiltration within 15 days, the system must be expanded within 120 days. Air infiltration is determined by monitoring well head temperature and oxygen or nitrogen levels. Additional wells will be installed within 60 days in 1.) active cells after waste has been in place for 5 or more years and 2.) closed or cells at final grade for 2 or more years.

To show compliance with the surface methane standard of 500 ppm, the entire perimeter of the collection area is monitored quarterly (take background concentrations upwind and downwind outside the landfill boundaries). The surface monitoring is performed 5 to 10 cm. above ground surface.

If there is an exceedance of the 500 ppm standard, the location of the exceedance must be marked on a site map. Within 10 days, repairs to the landfill cover or vacuum adjustment must be performed and the area must be rechecked within 10 days. If there are three excellencies in a quarter, new well(s) or a collection device must be installed within 120 days. If the area is in compliance after the recheck, monitor the area for one month from the date of the exceedance. In addition, a program must be established to monitor cover integrity and implement repairs on a monthly basis.

<u>Monitoring of Operations</u> Sample ports and a thermometer will be installed at each well head. Monthly pressure measurements, nitrogen or oxygen levels and temperature readings will be recorded. Enclosed combustors will be equipped with a continuous temperature recorder and a gas flow rate measuring device which records flow every 15 minutes. Open flares will have a pilot light sensor and a gas flow recorder which records flow every 15 minutes. Other devices can be used after submitting proper operating, performance and monitoring procedures.

Methane concentrations must be monitored quarterly at closed landfills. If there are no exceedances for three quarters, the annual monitoring can be skipped. Any exceedence returns the landfill to quarterly monitoring.

Reporting Requirements An initial design capacity report will be submitted 90 days from the issuance of a construction or operating permit or 30 days from the date of construction. reconstruction or initial acceptance of solid waste. The report will contain a site map or plot and the initial design capacity. The report will be amended within 90 days of the issuance of any permit which increases landfill capacity.

Initial and annual NMOC emission rate reports must be submitted. They will contain the emission rate, data calculations and measurements used in determining the emission rate. These reports will be submitted until a collection and control system has been installed, in operation and in compliance.

A collection and control system design plan will be submitted within one year of the first report where emissions exceed 50 Mg/yr.

A closure report will be submitted within 30 days of waste acceptance cessation.

An equipment removal report will be submitted 30 days prior to the removal or cessation of operation of control equipment.

Annual reports of the recorded information form the collection system are required. The initial report is due within 180 days of installation and startup and shall include the initial performance report.

Record Keeping Requirements Records of the maximum design capacity, current amount of waste in-place, and the year-by-year acceptance rate will be kept for at least 5 years. The initial performance test will be kept for the life of the control equipment and subsequent tests and monitoring records will be kept for 5 years. Continuous records of equipment operating parameters will be kept for 5 years. A plot map showing each existing and planned collector in the system will be kept. Records of all exceedences from the collection and control system will be kept for 5 years.

Specifications For Active Collection Systems Active collection wells, collectors or other extraction devices will be designed by a professional engineer and will achieve comprehensive control of all gas producing areas and surface gas emissions. Gas collection systems will be constructed of nonporus corrosion resistant materials of suitable dimensions to convey the projected flow, withstand vehicle traffic and other forces. The system shall extend to comply with all emission and migration standards. Gas moving equipment shall be sized to handle the maximum gas generation flow rate expected over its intended use period.

ES/kt

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 76

[AD–FRL–5666–1]

RIN 2060–AF48

Acid Rain Program; Nitrogen Oxides Emission Reduction Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates standards for the second phase of the Nitrogen Oxides Reduction Program under Title IV of the Clean Air Act ("CAA" or "the Act") by establishing nitrogen oxides (NO_X) emission limitations for certain coal-fired electric utility units and revising NO_X emission limitations for others as specified in section 407(b)(2) of the Act. The emission limitations will reduce the serious adverse effects of NO_X emissions on human health, visibility, ecosystems, and materials.

EFFECTIVE DATE: December 19, 1996.

ADDRESSES: *Docket.* Docket No. A–95–28, containing information considered during development of the promulgated standards, is available for public inspection and copying between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket Section (LE–131), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, DC 20460. A reasonable fee may be charged for copying.

Background information document. The background information document containing responses to public comments on the proposed standards may be obtained from the docket. Please refer to "Phase II Nitrogen Oxides Emission Reduction Program—Response to Comments Document".

FOR FURTHER INFORMATION CONTACT: Peter Tsirigotis, Source Assessment Branch, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, DC 20460 (202–233–9620).

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities regulated by this action are electric service providers that run or operate coal-fired electric utility boilers including dry bottom wall-fired and tangentially fired boilers (Group 1) and certain other boiler types including boilers applying cell-burner technology, cyclone boilers, wet bottom boilers, and other types of coal-fired boilers (Group 2). Regulated entities and boilers include:

Regulated Entities	Regulated Boilers
Electric Service Providers.	Dry bottom wall-fired. Tangentially fired. Cell Burners. Cyclones (larger than 155 MWe). Vertically fired. Wet bottoms (larger than 65 MWe).

This table is not intended to represent a definitive enumeration of all existing and future entities regulated by this action. Rather, its intent is to provide a general guide for readers and to list entities that EPA is now aware will be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your (facility, company, business, organization, etc.) is regulated by this action, you should carefully examine the applicability criteria in §§ 72.6 and 76.1 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the person named in the preceding "For Further Information Contact" section.

The information in this preamble is organized as follows:

I. Rule Background

A. Purpose of Acid Rain NO_X Emission Reduction Program

The primary purpose of the Acid Rain NO_X Emission Reduction Program is to reduce the multiple adverse effects of the oxides of nitrogen, a family of highly reactive gaseous compounds that contribute to air and water pollution, by substantially reducing annual emissions from coal-fired power plants. Since the 1970 passage of the Clean Air Act, NO_X has increased about 7%; it is the only conventional air pollutant to show an increase nationwide.

Electric utilities are a major contributor to NO_X emissions nationwide: in 1980, they accounted for 30 percent of total NO_X emissions and, from 1980 to 1990, their contribution rose to 32 percent of total NO_X emissions. In 1994, electric utility emissions represented about 33 percent of the total annual NO_X emissions. Approximately 90 percent of estimated electric utility NO_X emissions were attributed to coal combustion (see docket item IV–A–8 (USEPA, National Air Pollution Emission Trends, 1900–1994 (EPA–454/R–95–011) at 2–2, October 1995)).

The NO_X emissions discharged into the atmosphere from the burning of fossil fuels consists primarily of nitric oxide (NO). Much of the NO, however, reacts with organic radicals in the air to form nitrogen dioxide (NO_2) and, over longer periods of time, reacts with and forms other pollutants, including ozone (O_3), nitric acid (HNO_3) and fine particles. These pollutants are harmful to public health and the environment.

NO_2 and airborne nitrate also degrade visibility, and when they return to the earth through rain, snow, or fog ("wet deposition") or as gases ("dry deposition"), they contribute to acidification of lakes and streams and to excessive nitrogen loadings to estuaries and coastal water systems such as in the Chesapeake Bay ("eutrophication").

NO_2 has been documented to cause eye irritation, either by itself or when oxidized photochemically into peroxyacetyl nitrate (PAN). Ozone, the most abundant of the photochemical oxidants, is a highly reactive chemical compound which can have serious adverse effects on human health, plants, animals, and materials. Fine particles at current ambient levels contribute adversely to morbidity and mortality.

significant adverse impact on a substantial number of small entities. EPA notes that it also analyzed in detail the potential impact of the final rule on various financial measures of the 15 adversely impacted small utilities' profitability and short- and long-term solvency. The results show that, though the financial impact of compliance with this rule for the 15 small utilities is greater than that for medium and large utilities, the impact of the rule, as reflected in changes in various financial measures (such as return on equity and return on assets), is not significant (see docket item V-B-1 (RIA, EPA's Small Entity Screening Analysis)).

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has determined that this rule will have no significant adverse effect on a substantial number of small entities.

F. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of the rule in today's Federal Register. This rule is a "major rule" as defined by 5 U.S.C. 804(2).

G. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

List of Subjects in 40 CFR Part 76

Environmental protection, Acid rain program, Air pollution control, Nitrogen oxide, Reporting and recordkeeping requirements.

Dated: December 10, 1996.

Carol M. Browner,

Administrator.

PART 76—[AMENDED]

1. The authority citation for part 76 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 76.2 is amended by revising the definition of "coal-fired utility unit" and "wet bottom" and adding, in alphabetical order, definitions for "arch-fired boiler", "boiler capacity", "coal-fired utility boiler", "combustion controls", "fluidized bed combustor boiler", "maximum continuous steam flow at 100% of load" "non-plug-in combustion controls", "plug-in combustion controls", and "vertically fired boiler", to read as follows:

§ 76.2 Definitions.

* * * * *

Arch-fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are at an angle significantly different from the horizontal axis and the vertical axis. This definition shall include only the following units: Holtwood unit 17, Hunlock unit 6, and Sunbury units 1A, 1B, 2A, and 2B. This definition shall exclude dry bottom turbo fired boilers.

* * * * *

Coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in § 72.2 of this chapter.

* * * * *

Combustion controls means technology that minimizes NO_X formation by staging fuel and combustion air flows in a boiler. This definition shall include low NO_X burners, overfire air, or low NO_X burners with overfire air.

* * * * *

Maximum Continuous Steam Flow at 100% of Load means the maximum capacity of a boiler as reported in item 3 (Maximum Continuous Steam Flow at 100% Load in thousand pounds per hour), Section C (design parameters), Part III (boiler information) of the Department of Energy's Form EIA–767 for 1995.

* * * * *

Non-plug-in combustion controls means the replacement, in a cell burner boiler, of the portions of the waterwalls containing the cell burners by new portions of the waterwalls containing low NO_X burners or low NO_X burners with overfire air.

* * * * *

Plug-in combustion controls means the replacement, in a cell burner boiler, of existing cell burners by low NO_X burners or low NO_X burners with overfire air.

* * * * *

Vertically fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are horizontal or at an angle. This definition shall include dry bottom roof-fired boilers and dry bottom top-fired boilers, and shall exclude dry bottom arch-fired boilers and dry bottom turbo-fired boilers.

* * * * *

Wet bottom means that the ash is removed from the furnace in a molten state. The term "wet bottom boiler" shall include: wet bottom wall-fired boilers, including wet bottom turbo-fired boilers; and wet bottom boilers otherwise meeting the definition of vertically fired boilers, including wet bottom arch-fired boilers, wet bottom roof-fired boilers, and wet bottom top-fired boilers. The term "wet bottom boiler" shall exclude cyclone boilers and tangentially fired boilers.

§ 76.5 [Amended]

3. Section 76.5 is amended by remaing paragraph (g).

4. Section 76.6 is revised to read as follows:

§ 76.6 NO_X emission limitations for Group 2 boilers.

(a) Beginning January 1, 2000 or, for a unit subject to section 409(b) of the Act, the date on which the unit is required to meet Acid Rain emission reduction requirements for SO_2, the owner or operator of a Group 2, Phase II coal-fired boiler with a cell burner boiler, cyclone boiler, a wet bottom boiler, or a vertically fired boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.10 or 76.11:

(1) 0.68 lb/mmBtu of heat input on an annual average basis for cell burner boilers. The NO_X emission control technology on which the emission limitation is based is plug-in combustion controls or non-plug-in combustion controls. Except as provided in § 76.5(d), the owner or operator of a unit with a cell burner boiler that installs non-plug-in combustion controls after November 15, 1990 shall comply with the emission limitation applicable to cell burner boilers. The owner or operator of a unit with a cell burner that installs non-plug-in combustion controls on or before November 15, 1990 shall comply with the applicable emission limitation for dry bottom wall-fired boilers.

(2) 0.86 lb/mmBtu of heat input on an annual average basis for cyclone boilers with a Maximum Continuous Steam Flow at 100% of Load of greater than 1060 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(3) 0.84 lb/mmBtu of heat input on an annual average basis for wet bottom boilers, with a Maximum Continuous Steam Flow at 100% of Load of greater than 450 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(4) 0.80 lb/mmBtu of heat input on an annual average basis for vertically fired boilers. The NO_X emission control technology on which the emission limitation is based is combustion controls.

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter. 5. Section 76.7 is amended by adding paragraphs (a) and (b) to read as follows:

§ 76.7 Revised NO_X emission limitations for Group 1, Phase II boilers.

(a) Beginning January 1, 2000, the owner or operator of a Group 1, Phase II coal-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.8, 76.10, or 76.11:

(1) 0.40 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.46 lb/ mmBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter.

6. Section 76.8 is amended by: removing from paragraph (a)(2) the words "any revised NO_X emission limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act" and adding, in their place, the words "§ 76.7"; removing from paragraph (a)(5) the words "§§ 76.5(g) and if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act,"; and removing from paragraphs (e)(3)(iii)(A) and (B) the words "§ 76.5(g) and, if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act,".

§ 76.10 [Amended]

7. Section 76.10 is amended by removing from paragraph (f)(1)(iii) the words "§§ 76.5(g) or 76.6" and adding, in their place, the words "§§ 76.6 or 76.7".

8. Section 76.16 is added to read as follows: removed 5/1/98

§ 76.16 Alternative compliance.

(a)(1) A State or group of States may submit a petition requesting that the Administrator, or the Administrator, on his or her own motion, may:

(i) Require the owners or operators of the Group 1, Phase II coal-fired utility units with a tangentially fired boiler or a dry bottom wall fired boiler in the State or the group of States to be subject to the applicable emission limitations for NO_X in § 76.5, in lieu of the applicable emission limitations for NO_X in § 76.7; and

(ii) Provide that the owners or operators of the Group 2 coal-fired utility units with a cell burner boiler, cyclone boiler, wet bottom boiler, or vertically fired boiler in the State or the group of States are not subject to the applicable emission limitations for NO_X in § 76.6.

(2) A petition under paragraph (a)(1) of this section must demonstrate that the requirements in paragraphs (b)(1) and (2) of this section are met.

(3) A petition under paragraph (a)(1) of this section may be submitted, but may not be approved by the Administrator, before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable.

(b) The Administrator may take the actions set forth in paragraphs (a)(1)(i) and (ii) of this section if he or she finds that, under the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States:

(1) Each unit that is in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part

(i) Is subject to a cap on total annual NO_X emissions or two or more seasonal caps that together limit total annual NO_X emissions;

(ii) May trade authorizations to emit NO_X within each such cap; and

(iii) Must use NO_X emission authorizations to account for the NO_X emissions by such unit and to account for the NO_X emissions resulting from reducing utilization of such unit below its baseline utilization (adjusted for changes in demand for electricity) and shifting utilization to any other unit, or combustion device serving a generator that produces electricity for sale, that is not subject to each such cap; and

(2)(i) Total annual NO_X emissions by all units that are in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part will be lower than total annual NO_X emissions by such units if each such unit is treated as subject to the applicable emission limitation in §§ 76.5, 76.6, or 76.7 that would apply but for the provisions of this section.

(ii) In the case of a petition under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to submission of the petition but, in any event, for no later than 1999. In the case of action by the Administrator on his or her own motion under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to issuance of the draft decision under paragraph (c) of this section, but, in any event, for no later than 1999.

(c) In acting on a petition or on his or her own motion under paragraph (a) of this section, the Administrator will issue for public comment a draft decision on the petition or a draft decision to act on his or her own motion and then a final decision. The Administrator may issue a draft decision, but not final decision, on a petition or on his or her own motion before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable. The draft decision will set forth procedures that will govern issuance of the final decision and will provide for:

(1) Service of notice of issuance of the draft decision on.

(i) Any interested person;

(ii) The air pollution control agencies that have jurisdiction over a unit covered by the draft decision, are in a State whose air quality may be affected by the draft decision and that is contiguous to a State in which such a unit is located, or are in a State that is within 50 miles of a unit covered by the draft decision; and

(iii) On any federally recognized Indian Tribe in an area in which a unit covered by the draft decision is located, whose air quality may be affected by the draft decision and that is in an area that is contiguous to a State in which such a unit is located, or that is in an area that is within 50 miles of a unit covered by the draft decision;

(2) Publication of notice of issuance of the draft decision in the Federal Register and in any State publication designed to give general public notice in the States in which the units covered by the draft decision are located;

(3) A 30-day public comment period and extension or reopening of the comment period by the Administrator for good cause;

(4) A public hearing, upon request or on the Administrator's own motion, to the extent the Administrator determines that a public hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft decision;

(5) Consideration by the Administrator of the comments on the draft decision received during the public comment period or any public hearing and written response by the Administrator to any such relevant comments;

(6) Notice of issuance of a final decision using the methods set forth in paragraphs (c)(1) and (2) of this section for providing notice of the draft decision; and

(7) Appeals, governed by part 78 of this chapter, of the final decision.

(d) If, after the Administrator issues a final decision under paragraph (c) of this section and takes the actions set forth in paragraphs (a)(1)(i) and (ii) of this section with regard to a State or group of States, a State Implementation Plan or Federal Implementation Plan covering the entire State or entire group of States is revised in a way that may affect the basis for the findings on which such decision is based, the Administrator may, upon petition or on his or her own motion, reconsider such decision.

(e) For purposes of this section, the term "State" shall mean one of the 48 contiguous States or the District of Columbia.

Appendix B to Part 76 [Amended]

9. Appendix B is amended by: removing from the heading the words "Group 1, Phase I" and adding, in their place, the words "Group 1"; removing from section 1 the words "average cost" and adding, in their place, the word "cost"; removing from section 1 the words "average capital costs and cost-effectiveness" and adding, in their place, the words "capital costs and cost effectiveness"; removing from section 1 the words "as determined in section 3 below"; removing from section 1 the words "only overfire air" and adding, in their place, the words "overfire air"; removing from section 1 the words "only separated overfire air" and adding, in their place, the words "separated overfire air"; removing from, the heading section 1 and the introductory text of section 2 the words "Group 1, Phase I" in each place that the words appear and adding, in their place, the words "Group 1"; removing section 2.4; and removing and reserving section 3.

[FR Doc. 96-31839 Filed 12-18-96; 8:45 am]

BILLING CODE 6560-50-P

significant adverse impact on a substantial number of small entities. EPA notes that it also analyzed in detail the potential impact of the final rule on various financial measures of the 15 adversely impacted small utilities' profitability and short- and long-term solvency. The results show that, though the financial impact of compliance with this rule for the 15 small utilities is greater than that for medium and large utilities, the impact of the rule, as reflected in changes in various financial measures (such as return on equity and return on assets), is not significant (see docket item V–B–1 (RIA, EPA's Small Entity Screening Analysis)).

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has determined that this rule will have no significant adverse effect on a substantial number of small entities.

F. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of the rule in today's **Federal Register**. This rule is a "major rule" as defined by 5 U.S.C. 804(2).

G. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

List of Subjects in 40 CFR Part 76

Environmental protection, Acid rain program, Air pollution control, Nitrogen oxide, Reporting and recordkeeping requirements.

Dated: December 10, 1996.

Carol M. Browner,

Administrator.

PART 76—[AMENDED]

1. The authority citation for part 76 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 76.2 is amended by revising the definition of "coal-fired utility unit" and "wet bottom" and adding, in alphabetical order, definitions for "arch-fired boiler", "boiler capacity", "coal-fired utility boiler", "combustion controls", "fluidized bed combustor boiler", "maximum continuous steam flow at 100% of load" "non-plug-in combustion controls", "plug-in combustion controls", and "vertically fired boiler", to read as follows:

§ 76.2 Definitions.

* * * * *

Arch-fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are at an angle significantly different from the horizontal axis and the vertical axis. This definition shall include only the following units: Holtwood unit 17, Hunlock unit 6, and Sunbury units 1A, 1B, 2A, and 2B. This definition shall exclude dry bottom turbo fired boilers.

* * * * *

Coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in § 72.2 of this chapter.

* * * * *

Combustion controls means technology that minimizes NO_X formation by staging fuel and combustion air flows in a boiler. This definition shall include low NO_X burners, overfire air, or low NO_X burners with overfire air.

* * * * *

Maximum Continuous Steam Flow at 100% of Load means the maximum capacity of a boiler as reported in item 3 (Maximum Continuous Steam Flow at 100% Load in thousand pounds per hour), Section C (design parameters), Part III (boiler information) of the Department of Energy's Form EIA–767 for 1995.

* * * * *

Non-plug-in combustion controls means the replacement, in a cell burner boiler, of the portions of the waterwalls containing the cell burners by new portions of the waterwalls containing low NO_X burners or low NO_X burners with overfire air.

* * * * *

Plug-in combustion controls means the replacement, in a cell burner boiler, of existing cell burners by low NO_X burners or low NO_X burners with overfire air.

* * * * *

Vertically fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are horizontal or at an angle. This definition shall include dry bottom roof-fired boilers and dry bottom top-fired boilers, and shall exclude dry bottom arch-fired boilers and dry bottom turbo-fired boilers.

* * * * *

Wet bottom means that the ash is removed from the furnace in a molten state. The term "wet bottom boiler" shall include: wet bottom wall-fired boilers, including wet bottom turbo-fired boilers; and wet bottom boilers otherwise meeting the definition of vertically fired boilers, including wet bottom arch-fired boilers, wet bottom roof-fired boilers, and wet bottom top-fired boilers. The term "wet bottom boiler" shall exclude cyclone boilers and tangentially fired boilers.

§ 76.5 [Amended]

3. Section 76.5 is amended by removing ~~remaing~~ paragraph (g).

4. Section 76.6 is revised to read as follows:

§ 76.6 NO_X emission limitations for Group 2 boilers.

(a) Beginning January 1, 2000 or, for a unit subject to section 409(b) of the Act, the date on which the unit is required to meet Acid Rain emission reduction requirements for SO_2, the owner or operator of a Group 2, Phase II coal-fired boiler with a cell burner boiler, cyclone boiler, a wet bottom boiler, or a vertically fired boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.10 or 76.11:

(1) 0.68 lb/mmBtu of heat input on an annual average basis for cell burner boilers. The NO_X emission control technology on which the emission limitation is based is plug-in combustion controls or non-plug-in combustion controls. Except as provided in § 76.5(d), the owner or operator of a unit with a cell burner boiler that installs non-plug-in combustion controls after November 15, 1990 shall comply with the emission limitation applicable to cell burner boilers. The owner or operator of a unit with a cell burner that installs non-plug-in combustion controls on or before November 15, 1990 shall comply with the applicable emission limitation for dry bottom wall-fired boilers.

(2) 0.86 lb/mmBtu of heat input on an annual average basis for cyclone boilers with a Maximum Continuous Steam Flow at 100% of Load of greater than 1060 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(3) 0.84 lb/mmBtu of heat input on an annual average basis for wet bottom boilers, with a Maximum Continuous Steam Flow at 100% of Load of greater than 450 lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(4) 0.80 lb/mmBtu of heat input on an annual average basis for vertically fired boilers. The NO_X emission control technology on which the emission limitation is based is combustion controls.

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter. 5. Section 76.7 is amended by adding paragraphs (a) and (b) to read as follows:

§ 76.7 Revised NO_X emission limitations for Group 1, Phase II boilers.

(a) Beginning January 1, 2000, the owner or operator of a Group 1, Phase II coal-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in §§ 76.8, 76.10, or 76.11:

(1) 0.40 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.46 lb/ mmBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter.

6. Section 76.8 is amended by: removing from paragraph (a)(2) the words "any revised NO_X emission limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act" and adding, in their place, the words "§ 76.7"; removing from paragraph (a)(5) the words "§§ 76.5(g) and if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act,"; and removing from paragraphs (e)(3)(iii)(A) and (B) the words "§ 76.5(g) and, if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act,".

§ 76.10 [Amended]

7. Section 76.10 is amended by removing from paragraph (f)(1)(iii) the words "§§ 76.5(g) or 76.6" and adding, in their place, the words "§§ 76.6 or 76.7".

8. Section 76.16 is added to read as follows:

§ 76.16 Alternative compliance.

(a)(1) A State or group of States may submit a petition requesting that the Administrator, or the Administrator, on his or her own motion, may:

(i) Require the owners or operators of the Group 1, Phase II coal-fired utility units with a tangentially fired boiler or a dry bottom wall fired boiler in the State or the group of States to be subject to the applicable emission limitations for NO_X in § 76.5, in lieu of the applicable emission limitations for NO_X in § 76.7; and

(ii) Provide that the owners or operators of the Group 2 coal-fired utility units with a cell burner boiler, cyclone boiler, wet bottom boiler, or vertically fired boiler in the State or the group of States are not subject to the applicable emission limitations for NO_X in § 76.6.

(2) A petition under paragraph (a)(1) of this section must demonstrate that the requirements in paragraphs (b)(1) and (2) of this section are met.

(3) A petition under paragraph (a)(1) of this section may be submitted, but may not be approved by the Administrator, before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable.

(b) The Administrator may take the actions set forth in paragraphs (a)(1)(i) and (ii) of this section if he or she finds that, under the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States:

(1) Each unit that is in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part

(i) Is subject to a cap on total annual NO_X emissions or two or more seasonal caps that together limit total annual NO_X emissions;

(ii) May trade authorizations to emit NO_X within each such cap; and

(iii) Must use NO_X emission authorizations to account for the NO_X emissions by such unit and to account for the NO_X emissions resulting from reducing utilization of such unit below its baseline utilization (adjusted for changes in demand for electricity) and shifting utilization to any other unit, or combustion device serving a generator that produces electricity for sale, that is not subject to each such cap; and

(2)(i) Total annual NO_X emissions by all units that are in the State or the group of States and that, but for the provisions of this section, would be subject to emission limitations under this part will be lower than total annual NO_X emissions by such units if each such unit is treated as subject to the applicable emission limitation in §§ 76.5, 76.6, or 76.7 that would apply but for the provisions of this section.

(ii) In the case of a petition under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to submission of the petition but, in any event, for no later than 1999. In the case of action by the Administrator on his or her own motion under paragraph (a) of this section, total annual NO_X emissions by the units will be determined using the actual utilizations of the units for the last full calendar year prior to issuance of the draft decision under paragraph (c) of this section, but, in any event, for no later than 1999.

(c) In acting on a petition or on his or her own motion under paragraph (a) of this section, the Administrator will issue for public comment a draft decision on the petition or a draft decision to act on his or her own motion and then a final decision. The Administrator may issue a draft decision, but not final decision, on a petition or on his or her own motion before the State Implementation Plan or Federal Implementation Plan covering the entire State or the State Implementation Plans or Federal Implementation Plans covering the entire group of States become final and federally enforceable. The draft decision will set forth procedures that will govern issuance of the final decision and will provide for:

(1) Service of notice of issuance of the draft decision on.

(i) Any interested person;

(ii) The air pollution control agencies that have jurisdiction over a unit covered by the draft decision, are in a State whose air quality may be affected by the draft decision and that is contiguous to a State in which such a unit is located, or are in a State that is within 50 miles of a unit covered by the draft decision; and

(iii) On any federally recognized Indian Tribe in an area in which a unit covered by the draft decision is located, whose air quality may be affected by the draft decision and that is in an area that is contiguous to a State in which such a unit is located, or that is in an area that is within 50 miles of a unit covered by the draft decision;

(2) Publication of notice of issuance of the draft decision in the **Federal Register** and in any State publication designed to give general public notice in the States in which the units covered by the draft decision are located;

(3) A 30-day public comment period and extension or reopening of the comment period by the Administrator for good cause;

(4) A public hearing, upon request or on the Administrator's own motion, to the extent the Administrator determines that a public hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft decision;

(5) Consideration by the Administrator of the comments on the draft decision received during the public comment period or any public hearing and written response by the Administrator to any such relevant comments;

(6) Notice of issuance of a final decision using the methods set forth in paragraphs (c)(1) and (2) of this section for providing notice of the draft decision; and

(7) Appeals, governed by part 78 of this chapter, of the final decision.

(d) If, after the Administrator issues a final decision under paragraph (c) of this section and takes the actions set forth in paragraphs (a)(1)(i) and (ii) of this section with regard to a State or group of States, a State Implementation Plan or Federal Implementation Plan covering the entire State or entire group of States is revised in a way that may affect the basis for the findings on which such decision is based, the Administrator may, upon petition or on his or her own motion, reconsider such decision.

(e) For purposes of this section, the term "State" shall mean one of the 48 contiguous States or the District of Columbia.

Appendix B to Part 76 [Amended]

9. Appendix B is amended by: removing from the heading the words "Group 1, Phase I" and adding, in their place, the words "Group 1"; removing from section 1 the words "average cost" and adding, in their place, the word "cost"; removing from section 1 the words "average capital costs and cost-effectiveness" and adding, in their place, the words "capital costs and cost effectiveness"; removing from section 1 the words "as determined in section 3 below"; removing from section 1 the words "only overfire air" and adding, in their place, the words "overfire air"; removing from section 1 the words "only separated overfire air" and adding, in their place, the words "separated overfire air"; removing from, the heading section 1 and the introductory text of section 2 the words "Group 1, Phase I" in each place that the words appear and adding, in their place, the words "Group 1"; removing section 2.4; and removing and reserving section 3.

[FR Doc. 96–31839 Filed 12–18–96; 8:45 am]

BILLING CODE 6560–50–P

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

EPA-453/R-96-013a
October 1996

Air

Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Interim Final Report

Volume 1.

PREFACE

Overview of Report

This interim final report on hazardous air pollutant (HAP) emissions from fossil fuel-fired electric utility steam generating units (i.e., utilities) has been prepared by the United States Environmental Protection Agency (EPA) pursuant to section 112(n)(1)(A) of the Clean Air Act, as amended in 1990 (the Act). This report provides the Congress and the public with information regarding the emissions, fate, and transport of utility HAPs.

The primary components of this interim report are the following: (1) a description of the industry; (2) an analysis of emissions data; (3) an assessment of hazards and risks due to inhalation exposures to numerous HAPs (e.g., arsenic, nickel, cadmium, chromium, beryllium, and others [but excluding mercury]); (4) an assessment of risks due to multipathway (inhalation plus non-inhalation) exposure to one class of HAPs (radionuclides); (5) a general assessment of the fate and transport of mercury through various environmental media; and (6) a discussion of alternative control strategies.

The assessment for mercury in this interim report includes a description of mercury emissions, deposition estimates, control technologies, and a dispersion and fate modeling assessment which includes predicted levels of mercury in various media (including soil, water, and freshwater fish). These predicted levels are based on modeling of mercury emissions from four representative utility plants using hypothetical scenarios. The EPA has not evaluated exposures to mercury emissions from utilities for humans or wildlife in this interim report. If appropriate and feasible, the EPA may include these analyses in the final report.

To provide general information regarding potential background levels of several HAPs (i.e., mercury, arsenic, cadmium, lead, and dioxins) in the environment due to all sources (natural and anthropogenic), this interim report presents measured levels in various media (e.g., soil, air, water, and food products) as reported by various studies.

Assessments of human exposures to mercury and the associated risks of health effects were included in previous drafts of this report and in a related draft EPA report (Mercury Study Report to Congress [i.e., mercury study]). However, during external review of these draft reports, several critical issues related to the mercury risk assessment, including the impending release of new mercury health data, were raised. As a result of that review, the Agency plans to complete the mercury study when two important on-going human health studies are published and reviewed. At this time, the EPA believes that it is appropriate to exclude such assessments for mercury until after the mercury study is issued. However, this issue is still under consideration and negotiation, and may be dependent on results of additional peer review and other factors.

With regard to non-inhalation exposures (e.g., ingestion) to other HAPs, this report presents a limited qualitative discussion of arsenic, cadmium, dioxins, and lead. However, non-inhalation exposures were not estimated for these four HAPs because of the complexity and the intensive data requirements of such analyses. The EPA recognizes that non-inhalation exposures could be important for these HAPs. Therefore, the EPA has initiated a multipathway assessment for arsenic, and may consider conducting assessments for additional HAPs in the future.

This report is not a final report because the assessment of impacts to public health is not yet complete. For example, as indicated above, the evaluation of risks due to non-inhalation exposures was limited. In addition, conclusions regarding the significance of the risks, as well as the regulatory determination required in section 112(n)(1)(A), are not provided.

The EPA plans to publish a final utility HAP report at a later date which will include a more complete assessment of the exposures, hazards, and risks due to utility HAP emissions, and will include conclusions, as appropriate and feasible, regarding the significance of the risks and impacts to public health. In addition, the EPA plans to include in the final report a determination as to whether regulation of HAPs from utilities under section 112 is appropriate and necessary, as required by section 112(n)(1)(A) of the Act and a court order. This court order was issued pursuant to litigation filed against the EPA for failing to meet the statutory deadline for the utility report. The EPA intends that this regulatory determination would be a decision, based on the estimated impacts to public health, whether or not to pursue a regulatory development program under section 112. During any regulatory development process, the EPA would evaluate a range of potential control technologies and emission reduction options and their associated costs.

There are uncertainties, data gaps, and limitations to the current analyses, which are discussed throughout this interim report. If new data become available or improvements are made to the analyses, these changes will be included in the final report.

Peer Review

Draft versions of this report were reviewed during the summer of 1995 by numerous non-EPA scientists representing industry, environmental groups, academia, and other organizations. In the Spring of 1996, the draft report underwent additional review by EPA, State and local air pollution agencies, and other Federal agencies. In addition, a revised draft interim report underwent an expedited review (1 week) by State and local air pollution agencies and other Federal agencies during September 1996.

The EPA has revised the report, as appropriate, based on the reviewers' comments. However, there were several comments that could not be fully addressed because of limitations in data, methods, and resources. At the end of each Chapter, the EPA has included comments received from other Federal Agencies (e.g., Department of Energy, Food and Drug Administration, National Marine Fisheries Service) that were not fully addressed, along with relevant explanations, as appropriate.

Draft versions of this report, along with all the comments received, have been submitted to the docket (A-92-55) and are available for public inspection.

EXECUTIVE SUMMARY

ES.1 BACKGROUND

This interim final report on emissions of hazardous air pollutants (HAP) from fossil fuel-fired electric utility steam generating units (i.e., utilities) was prepared by the United States (U.S.) Environmental Protection Agency (EPA) pursuant to section 112(n)(1)(A) of the Clean Air Act (the Act), as amended in 1990. The primary components of this interim report are: (1) a description of the industry; (2) an analysis of emissions data; (3) an assessment of hazards and risks due to inhalation exposures to numerous HAPs (e.g., arsenic, nickel, chromium); (4) an assessment of risks due to multipathway (inhalation plus non-inhalation) exposure to one class of HAPs (i.e., radionuclides); (5) a general assessment of the fate and transport of mercury through environmental media; and (6) a discussion of alternative control strategies.

The study was based on two scenarios: (1) 1990 base year emissions; and (2) 2010 emissions. The 1990 scenario was chosen since that was the year the Amendments to the Act were passed and was the latest year for which utility operational data were available. The 2010 scenario was selected to meet the section 112(n)(1)(A) mandate to evaluate hazards "after imposition of the requirements of the Act." Primarily, this meant assessing the hazards after the on-going and future regulatory activities under other provisions of the Act (e.g., ambient air quality and acid rain programs) are in place. The 2010 scenario also included estimated changes in HAP emissions resulting from projected trends in fuel choices and electric power demands.

ES.2 DESCRIPTION OF INDUSTRY

A total of 684 utility plants were identified in the U.S. These utilities are fueled primarily by coal (59 percent of total units), oil (12 percent), or natural gas (29 percent). Many plants have two or more units (i.e., boilers) and several plants burn more than one type of fuel (e.g., contain both coal- and oil-fired boilers). There are 426 plants that burn coal as one of their fuels, 137 plants that burn oil, and 267 plants that burn natural gas.

There are many different types of facilities, varying in boiler type, emission control devices (controls), and other characteristics. Based on data for 1990, all coal-fired units and about one-third of oil-fired units use some form of particulate matter (PM) control. Approximately 15 percent of coal-fired units utilize add-on controls for sulfur dioxide (SO_2). Approximately 70 percent of oil- and gas-fired units employ controls for nitrogen oxides (NO_x); and 80 percent of coal-fired units have NO_x controls.

ES.3 EMISSIONS DATA ANALYSIS

Emission estimates for the years 1990 and 2010 were based on emissions test data from 52 units obtained from extensive emission tests by the Electric Power Research Institute (EPRI), the Department of Energy (DOE), the Northern States Power Company, and the EPA. The testing program was designed to test a wide range of facility types with a variety of control scenarios; therefore, the data are considered generally representative of the industry. However, there are uncertainties in the data because of the small sample sizes for specific boiler types and control scenarios.

These test data provided the basis for estimating average annual emissions for each of the 684 plants. A total of 67 HAPs were identified in the emissions testing program as potentially being emitted by utilities. Tables ES-1 and ES-2 present estimated emissions for a subset of HAPs.

The average annual emissions estimates are considered appropriate for assessing long-term exposures on a national basis. However, since the EPA did not have emissions test data for each utility in the U.S., there may be individual plants for which the EPA either underestimated or overestimated emissions. Based on an uncertainty analysis, the average annual emissions estimates are predicted to be roughly within a factor of plus or minus three of actual annual emissions. However, this analysis had limitations. For example, the analysis did not include data on potential upsets or unusual operating conditions; therefore, the range of uncertainty could be greater. The range of uncertainty for short-term emissions has not been determined.

ES.4 GENERAL APPROACH TO EXPOSURE AND RISK ASSESSMENT

Most of the risk assessment focused on inhalation exposure. All 67 HAPs were assessed for inhalation exposures, at least at a screening level. Non-inhalation exposures are presented for one class of HAP (radionuclides).

For many of the 67 HAPs, inhalation exposure is believed to be the dominant exposure pathway. However, for HAPs that are persistent, bioaccumulate, and are toxic by ingestion, the non-inhalation exposure pathways are likely to be more important. In addition to radionuclides, the EPA also identified five other HAPs (mercury, arsenic, dioxins, cadmium, and lead), that could present additional impacts due to non-inhalation exposures. The

Table ES-1. Nationwide Utility Emissions for a Subset of HAPs

HAP	Nationwide HAP emission estimates (tons per year)[a]					
	Coal (426 plants)		Oil (137 plants)		Natural gas (267 plants)	
	1990	2010	1990	2010	1990	2010
Arsenic	54	54	5	3	0.16	0.25
Cadmium	1.9	2.3	1.7	0.9	0.054	0.086
Chromium	70	83	4.7	2.4	1.2	1.9
Lead	72	83	11	5.6	0.44	0.68
Mercury	51	65	0.25	0.13	0.0016	0.0024
Nickel	48	57	390	200	2.3	3.5
Hydrogen chloride	140,000	150,000	2,900	1,500	NM[b]	NM
Hydrogen fluoride	20,000	26,000	140	73	NM	NM
Dioxins[c]	0.00015	0.00020	1×10^{-5}	5×10^{-6}	NM	NM

[a] The emissions estimates in this table are derived from model projections based on a limited sample of specific boiler types and control scenarios. Therefore, there are uncertainties in these numbers. Based on an uncertainty analysis conducted for this study, the EPA predicts that the emissions estimates for individual plants are generally within a factor of roughly three of actual emissions.

[b] NM = Not measured.

[c] *These emissions estimates were calculated using the toxic equivalency (TEQ) approach, which is* based on the summation of the emissions of each congener after adjusting for toxicity relative to 2,3,7,8-tetrachlorodibenzo-p-dioxin (i.e., 2,3,7,8-TCDD).

dispersion, fate, and environmental concentrations of mercury were evaluated; however, exposures and risks were not estimated. The other four HAPs (arsenic, dioxins, lead, and cadmium) were examined qualitatively for their potential for multipathway hazards. However, multipathway exposure assessments were not conducted for these four HAPs. The EPA recognizes that for mercury, as well as these other four HAPs, non-inhalation exposures could be important. Quantitative analyses were not performed for arsenic, cadmium, dioxins, and lead because of the complexity of such analyses, the intensive data requirements of such analyses, and because of the limited chemical-specific data available (e.g., chemical-specific air-to-plant biotransfer factors, bioconcentration factors, chemical-specific plant uptake rates) for conducting such analyses. The EPA plans to continue assessing the multipathway exposures and hazards for mercury. The EPA has initiated a multipathway assessment for arsenic. Multipathway analyses may be undertaken for some of the other HAPs (e.g., dioxins) in the future should the EPA determine that such analyses are feasible and warranted, and as resources allow.

Table ES-2. Estimated Emissions From Characteristic Utility Units (1990; tons per year)

Fuel:	Coal	Oil	Natural gas
Unit size (MWe):	325	160	240
Arsenic	0.081	0.016	0.0003
Cadmium	0.00051	0.0077	NC[b]
Chromium	0.086	0.018	NC
Lead	0.075	0.053	NC
Mercury	0.05	0.0012	NC
Hydrogen chloride	190	9.4	NC
Hydrogen fluoride	14	NC	NC
Dioxins[c]	0.00000014	0.000000035	NC
Nickel	NC	2.1	0.004

[a] There are uncertainties in these numbers. Based on an uncertainty analysis conducted for this study, the EPA predicts that the emissions estimates are generally within a factor of roughly three of actual emissions.

[b] NC = Not calculated.

[c] See footnote b of Table ES-1.

ES.5 SCREENING ASSESSMENT

Initially, the EPA conducted a screening assessment that considered inhalation and non-inhalation exposure routes for all 67 HAPs to identify priority HAPs for more detailed assessment. To screen for inhalation exposures, the EPA used the Human Exposure Model (HEM) to model the 67 HAPs from all 684 utility plants utilizing generally conservative assumptions (i.e., assumptions that are more likely to overestimate rather than underestimate risks) to estimate inhalation risks for maximally exposed individuals (MEIs). If the MEI risk was above a minimum measure (e.g., exposure greater than one-tenth the inhalation reference concentration [RfC] or cancer risk greater than 1 chance in 10 million), then the HAP was chosen for more study. For non-inhalation exposures, the 67 HAPs were prioritized by considering four criteria: (1) persistence; (2) tendency to bioaccumulate; (3) toxicity by ingestion; and (4) quantity of emissions.

Based on this assessment, 15 HAPs (arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, hydrogen chloride [HCl], hydrogen fluoride [HF], acrolein, dioxins, formaldehyde, n-nitrosodimethylamine, and radionuclides) were identified as priority based on their potential to pose impacts to public health due to inhalation or non-inhalation exposures. The other 52 HAPs were not evaluated beyond the screening assessment.

ES.6 INHALATION RISK ASSESSMENT -- LOCAL ANALYSIS

The EPA estimated inhalation exposures and risks due to dispersion of HAP emissions within 50 kilometers (km) of each of the 684 plants individually (i.e., local analysis). For 14 of the 15 HAPs, the HEM was used; for radionuclides, the Clean Air Act Assessment Package-1993 (CAP-93) model was used. The cancer risks for gas-fired plants were less than one chance in one million (i.e., 1×10^{-6}) and no noncancer hazards were identified; therefore, gas-fired plants are omitted from the following discussions.

In cases where data were missing or incomplete, the EPA had to make various assumptions. A few of these assumptions are more likely to overestimate risks. Other assumptions used are likely to underestimate risks. Based on an uncertainty analysis conducted for this study, it is estimated that these assumptions taken together lead to a reasonable high-end (i.e., conservative, but not overly conservative) estimate of the risks due to inhalation exposure within 50 km of plants. That is, the risk estimates from the local analysis are estimated to represent approximately the 90th to 95th percentile. Conservative estimates are considered appropriate so that errors are on the side of public health protection.

ES.6.1 <u>Inhalation Cancer Risks for Coal-fired Utilities Based on Local Analysis</u>

The large majority of coal-fired plants (424 of the 426 plants) are estimated to pose lifetime cancer risks (i.e., increased probability of an exposed person getting cancer during a lifetime) of less than 1 chance in 1 million (i.e., 1×10^{-6}) due to inhalation exposure. Only two of the 426 plants are estimated to pose inhalation risks greater than 1×10^{-6} (see Figure ES-1).

The increased lifetime cancer risk due to inhalation exposure to HAP emissions for the highest MEI, based on the local analysis, is estimated to be 5×10^{-6}. Arsenic and chromium are the HAPs contributing most to the inhalation cancer risks (Table ES-3). All other HAPs, including radionuclides, were estimated to present inhalation risks less than 1×10^{-6}.

Note: The maximum individual risk (MIR) is often presented in either scientific notation or as an exponent. For example, an increased cancer risk of one chance in one million can be expressed as 1×10^{-6} or as 1E-6.

Table ES-3. Summary of 1990 Inhalation Cancer Risk Estimates from Local Analysis for Coal-fired Utilities

HAP	MEI lifetime risk[a]	Population with lifetime risk > 1×10^{-6}	Number plants with MEI lifetime risk > 1×10^{-6}
Arsenic	3×10^{-6}	2,400	2
Chromium	2×10^{-6}	110	1
Total[b] (Aggregate of HAPs)	5×10^{-6}	2,400	2

[a] Estimated MEI risk due to inhalation exposure for the "highest risk" coal-fired plant. Based on an uncertainty analysis, these estimates are considered reasonable high-end estimates (roughly the 90th to 95th percentile) of the risks for the MEI due to inhalation exposure (see section ES.6.3).

[b] Estimated risk due to inhalation of the aggregate of HAPs assuming additivity of risk for 26 individual carcinogenic HAPs.

The cancer incidence in the U.S. due to inhalation exposure to HAP emissions (including radionuclides) from all 426 coal-fired utility plants based on the local analysis is estimated to be approximately 0.2 cancer case per year (cases/yr), or 1 case every 5 years.

ES.6.2 Inhalation Cancer Risks for Oil-fired Utilities Based on Local Analysis

The majority of the oil-fired plants (more than 114 of the 137 plants) are estimated to pose inhalation cancer risks less than 1×10^{-6}. However, up to 22 of the 137 oil-fired plants are estimated to present inhalation risks above 1×10^{-6} (see Figure ES-2). Nickel, arsenic, radionuclides, and chromium are the primary contributors to these cancer risks.

The highest contribution to the MEI risk is nickel. The range in MEI risk (see Table ES-4) reflects a range in assumptions regarding the form of nickel being emitted and the associated cancer potency. Nickel subsulfide is a known human carcinogen and appears to be the most carcinogenic form based on available data. Several other nickel species are also potentially carcinogenic but the potencies are not known.

To evaluate the range of potential risks due to nickel emissions, the EPA estimated risks due to nickel emissions using various assumptions for nickel cancer potency. For example, assuming the nickel mix is 100 percent as carcinogenic as nickel subsulfide, the highest MEI inhalation cancer risk due to the aggregate of HAP emissions from the highest risk oil-fired utility plant is estimated to be 1×10^{-4}. Assuming the nickel mix is 10 percent as carcinogenic as nickel subsulfide, the highest MEI inhalation risk is approximately 3×10^{-5}. The

Table ES-4. Summary of 1990 Inhalation Cancer Risk Estimates Based on Local Analysis for Oil-fired Utilities

HAP	Highest MEI lifetime risk[a]	Population with lifetime risk > 1×10^{-6}	Number plants with MEI lifetime risk > 1×10^{-6}
Nickel[b]	1×10^{-5} to 9×10^{-5}	2,400 to 1,600,000	2 to 20
Arsenic	1×10^{-5}	2,400	2
Radionuclides	1×10^{-5}	2,400	2
Chromium	5×10^{-6}	2,300	1
Cadmium	2×10^{-6}	45	1
Total[c] (aggregate)	3×10^{-5} to 1×10^{-4}	2,400 to 1,600,000	2 to 20

[a] Estimated MEI risk due to inhalation exposure to HAPs for the "highest risk" oil-fired plant. Based on an uncertainty analysis, these estimates are considered reasonable high-end estimates (roughly the 90th to 95th percentile) of the risks for the MEI due to inhalation exposure. See section ES.6.3 for discussion.

[b] These estimates are presented as a range because of the uncertainties associated with the nickel risk assessment. If the nickel mix is assumed to be 10% as carcinogenic as nickel subsulfide, then the MEI risk for nickel is estimated to be 1×10^{-5}. If the nickel mix is assumed to be 100% as carcinogenic as nickel subsulfide, the estimated MEI risk for nickel is 9×10^{-5}.

[c] Estimated risk due to inhalation of the aggregate of HAPs assuming additivity of risk for 14 individual carcinogenic HAPs. The low end of the range is based on assumption that the mix of nickel compounds is 10% as carcinogenic as nickel subsulfide. The high-end of the range is based on assumption that the mix of nickel compounds is 100% as carcinogenic as nickel subsulfide.

values in Figure ES-2 are based on the assumption that the nickel mix is 100 percent as carcinogenic as nickel subsulfide.

Estimated risks due to inhalation exposure for a subset of HAPs based on the local analysis are presented in Table ES-4. All other HAPs analyzed were estimated to pose inhalation cancer risks below 1×10^{-6} for all 137 oil-fired plants.

The cancer incidence in the U.S. due to inhalation exposure to HAP emissions (including radionuclides) from all 137 oil-fired utilities, based on the local analysis, is estimated to be between 0.3 and 0.7 cancer cases/yr. The high end of this range is based on the assumption that the nickel mix is as carcinogenic as nickel subsulfide. The low end of the range assumes that the mix of nickel is 10 percent as carcinogenic as nickel subsulfide.

ES.6.3 Inhalation Cancer Risks Based on Long-Range Transport Analysis

In addition to the above analyses, the EPA conducted long-range transport analyses to assess emissions dispersion and exposures on a national scale. The Regional Lagrangian Model of

Air Pollution (RELMAP) was used to estimate the dispersion of HAP

Note: The maximum individual risk (MIR) is often presented in either scientific notation or as an exponent. For example, an increased cancer risk of one chance in one million can be expressed as 1×10^{-6} or as 1E-6.

emissions from the facility stack out to the borders of the continental U.S. This is in contrast to the HEM, which estimates dispersion and air concentrations within 50 km of the source.

The RELMAP modeling was conducted for all coal- and oil-fired utilities, but was limited to mercury and arsenic. Only arsenic is discussed in this section; the modeling for mercury is presented in section 7. The long-range transport modeling of arsenic indicates that the local HEM analysis alone does not account for a substantial percentage of the population exposures due to utility emissions. A comparison of the HEM results to the RELMAP results for arsenic indicates that a significant portion of emissions disperse further than 50 km, apparently due to the tall stack heights and other dispersion factors. Based on the RELMAP analysis, the nationwide dispersion of arsenic emissions leads to an estimate of population exposure and cancer incidence that is approximately seven-fold greater than the population exposures and cancer incidence predicted by the HEM when only local dispersion is considered (see Table ES-5).

The RELMAP results for arsenic (which is emitted mainly as PM) were used to estimate the potential long-range transport inhalation exposures for cadmium, chromium, nickel, and radionuclides since it is believed that these other HAPs are also emitted as PM and exhibit proportional emission rates and atmospheric dispersion behavior similar to that of arsenic. Because the estimated population exposures resulting from the long-range transport analysis for arsenic were about seven times greater than the population exposures predicted by the local analysis alone, it was also assumed that this ratio also could hold true for nickel, chromium, cadmium, and radionuclides. Using this methodology, the cancer incidence for coal-fired utilities considering both local and long-range transport is estimated to be roughly 1.4 cases/yr (i.e., 0.2 x 7 = 1.4). The cancer incidence for oil-fired utilities (assuming the nickel mix is 100 percent as carcinogenic as nickel subsulfide) is estimated to be as high as 5 cases/yr (i.e., 0.7 x 7 = 4.9). These estimates should be viewed as highly uncertain high-end estimates (particularly the estimate of five cases/yr for oil-fired utilities) because of modeling uncertainties and extrapolations (e.g., using the modeling results for arsenic to predict dispersion and exposure for the other HAPs) and because of the assumption for nickel carcinogenicity.

For risks to the MEI, a comparison between the HEM local dispersion results and the long-range transport modeling results indicates that long-range transport is not as important for the MEI risks as it is for cancer incidence. For example, the MEI

Table ES-5. Summary of Inhalation Risk Estimates Due to Local and Long-range Transport

LOCAL IMPACTS (dispersion within 50 km of each utility plant)[d]				
	OIL-FIRED PLANTS		COAL-FIRED PLANTS	
Pollutant	Maximum exposed individual (MEI)	Annual increased cancer Incidence	Maximum exposed individual (MEI)	Annual increased cancer incidence
Radionuclides	1×10^{-5}	0.2	2×10^{-8}	0.1
Nickel[a]	9×10^{-5}	0.4	7×10^{-7}	0.005
Chromium	5×10^{-6}	0.02	2×10^{-6}	0.02
Arsenic	1×10^{-5}	0.04	3×10^{-6}	0.05
Cadmium	2×10^{-6}	0.005	2×10^{-7}	0.0006
All Others[b]	8×10^{-7}	0.005	8×10^{-7}	0.004
Total[c]	1×10^{-4}	0.7	5×10^{-6}	0.2
LOCAL PLUS LONG-RANGE IMPACTS (dispersion from utility emission points to borders of continental U.S.)[e]				
	OIL-FIRED PLANTS		COAL-FIRED PLANTS	
Pollutant	Maximum exposed individual (MEI)	Annual increased cancer incidence	Maximum exposed individual (MEI)	Annual increased cancer incidence
Radionuclides	Not estimated	1.4	Not estimated	0.7
Nickel[a]	9×10^{-5}	2.8	9×10^{-7}	0.035
Chromium	5×10^{-6}	0.14	3×10^{-6}	0.14
Arsenic	1×10^{-5}	0.28	4×10^{-6}	0.35
Cadmium	2×10^{-6}	0.035	3×10^{-7}	0.04
All Others[b]	8×10^{-7}	0.035	1×10^{-6}	0.03
Total[c]	1×10^{-4}	4.8	7×10^{-6}	1.3

[a] Assumes that the nickel mixture is as carcinogenic as nickel subsulfide.
[b] Estimated risks due to exposure to all remaining HAPs analyzed (i.e., excluding nickel, arsenic, chromium, cadmium, and radionuclides).
[c] This is the aggregate risk (i.e., the risk due to inhalation exposure to all carcinogenic HAPs, assuming additivity of risks).
[d] There are uncertainties associated with these risk estimates. See sections 6.4 for discussion.
[e] These risk estimates are based on an extrapolation of RELMAP modeling results for arsenic to other HAPs. Therefore, there are considerable uncertainties associated with these results. See sections 6.3 and 6.4 for discussion.

risk from the local analyses for coal-fired utilities (i.e., inhalation risk of 5×10^{-6}) is increased by approximately 40 percent to roughly 7×10^{-6} when ambient concentrations are added from long-range transport of arsenic from all other utilities in the continental U.S. For oil-fired utilities, the long-range transport of HAPs has no impact on the highest MEI inhalation risks because of the remote location of the two highest risk oil-fired plants. Table ES-5 presents a comparison of results from the local versus long-range transport analyses.

ES.6.3 Uncertainties with the Inhalation Cancer Risk Assessment

There are several areas of uncertainty in the inhalation risk assessment including: (1) the impacts of long-range transport; (2) the emissions and health effects of different forms of chromium and nickel; (3) the use of a linear non-threshold high-to-low dose extrapolation model for estimating cancer risks at low exposure concentrations; (4) the impacts of episodic releases resulting from upsets or unusual operating conditions; (5) how residence times and activity patterns impact the exposures; (6) the impacts on sensitive subpopulations; (7) the impacts of background exposures; and (8) the risk of complex pollutant mixtures.

The quantitative uncertainty analysis indicates that the MEI inhalation cancer risk estimates presented above from the local analysis are reasonable high-end estimates of the risks due to inhalation exposure within 50 km of each plant. That is, the estimates are considered generally conservative (i.e., roughly the 90th to 95th percentile). Conservative assumptions are considered appropriate so that errors are on the side of public health protection. The uncertainty analysis suggests that the most likely estimated inhalation risks for MEIs (i.e., central tendency MEI risk estimates) may be roughly 5 to 10 times lower than the MEI estimates presented above.

ES.6.4 Summary of the Inhalation Cancer Risks

For the majority of utility plants (approximately 662 of the 684 plants), the estimated inhalation cancer risks due to HAP emissions are less than 1×10^{-6}. However, several plants (2 coal-fired plants and between 2 and 22 oil-fired plants) are estimated to pose inhalation cancer risks above 1×10^{-6}, and one oil-fired plant is estimated to pose an MEI inhalation cancer risk between 3×10^{-5} and 1×10^{-4}. The cancer incidence in the U.S. due to inhalation exposure to HAP emissions from all utilities (coal-, oil- and gas-fired combined) is estimated to be between 0.5 and 6 cases/yr. Further research and evaluation is needed to more comprehensively assess the inhalation cancer risks, especially the impacts of long-range transport of HAPs and speciation of nickel.

ES.6.5 Inhalation Noncancer Risks

The EPA also assessed noncancer risks (i.e., health effects other than cancer) due to short- and long-term inhalation exposure. Manganese, HCl, HF, and acrolein were found to be the four HAPs of highest potential concern for noncancer effects.

Based on modeling HAPs for all 684 plants with the HEM, the estimated long-term ambient HAP concentrations were generally 100 to 10,000 times below the RfC or similar benchmark. The highest estimated long-term ambient HAP concentration was 10 times below the RfC. The RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of the daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without appreciable risk of deleterious effects during a lifetime.

Using a short-term air dispersion model that considers all reasonable meteorological conditions, the EPA modeled maximum one-hour concentrations for three HAPs (HCl, HF, and acrolein). The highest short-term exposure was 140 times below the acute reference level.

ES.7 MULTIPATHWAY ASSESSMENT

The utility HAPs were prioritized for potential non-inhalation exposures. The following characteristics were considered: (1) persistence, (2) toxicity, and (3) potential to bioaccumulate. Mercury, radionuclides, arsenic, dioxins, cadmium, and lead were selected as priority for multipathway assessment.

ES.7.1 Mercury Modeling Assessment

To assess the transport and deposition of mercury emissions from utilities and to estimate concentrations in environmental media and biota, three modeling efforts were undertaken: (1) long-range fate and transport modeling, (2) local scale dispersion modeling, and (3) modeling of environmental concentrations. The RELMAP was used to predict long-range dispersion and deposition across the continental U.S. For the local analysis, a model designed to predict deposition of HAPs within 50 km was used. The Indirect Exposure Model (IEM) was used to estimate environmental concentrations.

Three types of hypothetical locations were considered in the modeling analyses: (1) agricultural, (2) lacustrine (near lakes), and (3) urban. Using four model utility plants, and various assumptions and scenarios, mercury concentrations in various environmental media were estimated.

There are significant uncertainties in the models, data inputs, assumptions, and the quantitative results. However, the analyses were useful for gaining a better understanding of the fate and transport of mercury in the environment, and for estimating plausible levels in environmental media.

The modeling also provided information on whether local and/or long-range transport of mercury is important in a variety of scenarios. The models indicate that most of the mercury from utilities is transported further than 50 km from the source.

ES.7.1.1 General Findings for Mercury. Mercury emissions disperse in the atmosphere and deposit to land and water bodies. Deposition is of potential concern because mercury persists in the environment, and bioaccumulates in the food web (especially in the aquatic food web). The form of mercury found in fish tissue is predominantly methylmercury. Of all the media and biota studied, fish have the highest concentrations of mercury in the environment.

ES.7.1.2 Summary of Mercury Assessment Results for Utilities. For the year 1990, coal-fired utilities were estimated to emit approximately 51 tons per year (tpy) of mercury nationwide, which is approximately 21 percent of the 248 tpy of anthropogenic emissions of mercury estimated to be emitted in the U.S. for the years 1990 to 1992. The EPA also estimates that utility mercury emissions will increase to 65 tpy by the year 2010. If one assumes that current anthropogenic activity represents between 40 and 75 percent of the total emissions (anthropogenic plus other emissions [e.g., natural emissions]), one can calculate that U.S. utilities emit roughly 8 to 15 percent of the total emissions of mercury in the U.S.

Recent estimates of global anthropogenic mercury emissions are about 4,400 tpy. Point sources such as fuel combustion; waste incineration; industrial processes (e.g., chlor-alkali plants); and metal ore roasting, refining, and processing are the largest point source categories on a world-wide basis. Given this global estimate, U.S. anthropogenic mercury emissions could account for about 6 percent of the global total, and U.S. electric utilities would account for about 1 percent of global anthropogenic emissions (using 1990 emission estimates).

Based on the RELMAP modeling analysis, approximately 30 percent (i.e., 15 tpy) of utility mercury emissions deposit in the continental U.S. The estimated annual deposition rates resulting from utility mercury emissions range from 0.5 to greater than 10 micrograms per square meter. The highest deposition appears to occur in the eastern half of the U.S., particularly areas such as southeastern Great Lakes and Ohio River Valley, central and western Pennsylvania, large urban areas in the eastern U.S. (e.g., Washington, D.C., New York City) and various locations in the vicinity of large coal-fired utilities. Based on the limited available data, the RELMAP model seems to over- and underestimate mercury values within a factor of two and appears to be relatively unbiased in its predictions.

Although the amount of mercury being emitted from any single utility may seem relatively small, these emissions are of potential concern for a number of reasons. First, mercury is persistent. It is not degraded, but continually accumulates in the environment. Consequently, over time there is potential for concentrations in the environment to build up. Second, mercury bioaccumulates in the food web. Third, current scientific evidence indicates that most of the mercury emitted to the atmosphere from sources such as utilities, which have tall stacks, does not deposit near the source but is deposited farther away. As a result, even though the ambient concentration of mercury around a single source may not be elevated, there are sufficient data from which to conclude that the cumulative impact of many small sources may lead to the accumulation of mercury in the soils and sediments, and bioaccumulation in freshwater fish. Therefore, the incremental emissions of mercury from utilities, added to the mercury emissions from all of the other sources, contribute to overall environmental loadings, and thus, may contribute, to some degree, to the mercury levels in freshwater fish.

The modeling assessment in conjunction with available scientific knowledge, suggests that there is a plausible link between emissions of mercury from utilities and the mercury found in soil, water, air, and freshwater fish. As noted above, there are many sources of mercury emissions worldwide, both natural and anthropogenic. The fish methylmercury levels are probably due, in part, to mercury emissions from all of these various sources over time. The coal-fired utilities are one category of the mercury sources. The EPA has not yet determined whether the mercury emissions from utilities are a concern for public health.

The EPA recognizes that there are significant uncertainties regarding the extent of the exposures and risks due to utility mercury emissions, and that further research and evaluation is needed to reduce uncertainties and to characterize the exposures and risks. Areas of uncertainty include the following: (1) what exposure levels are likely to result in adverse health effects; (2) what percent of mercury emissions are elemental versus divalent mercury; (3) how much mercury is emitted from natural sources; (4) how much mercury is removed during coal cleaning; and (5) what affects the bioaccumulation of methylmercury in fish. The EPA plans to continue evaluating the exposures and public health impacts due to mercury emissions. In addition, the EPA plans to review new data (e.g., health and exposure data) as they become available and will consider the new data, as appropriate, in future assessments.

Regarding potential methods for reducing mercury emissions, the EPA has not identified any demonstrated add-on control technologies currently in use in the U.S. that effectively remove mercury from utility emissions. (However, there may be add-on control technologies used in other source categories that effectively reduce mercury emissions.) Based on available data, mercury removal by existing PM control devices on utilities varies considerably, ranging from 0 to 82 percent removal, with a median efficiency of 16 percent removal. Existing flue gas desulfurization (FGD) units exhibit poor mercury control, ranging from 0 to 59 percent removal, with a median removal of 17 percent. Pilot-scale studies have shown that mercury removal can be enhanced through the use of activated carbon injection. However, the limited results to date utilizing carbon injection are inconsistent and more data and research are needed. Other various pollution prevention strategies, such as coal cleaning, have shown some effectiveness in reducing utility emissions of mercury. Conventional coal cleaning removes, on average, approximately 21 percent of the mercury contained in the coal. Also, fuel switching, such as switching from coal to natural gas, would result in decreased emissions of mercury.

ES.7.2 Multipathway Assessment for Radionuclides

Radionuclide emissions from utilities may result in human exposure from multiple pathways including: (1) external radiation exposure from radionuclides suspended in air or deposited on the ground, and (2) internal exposure from the inhalation of airborne contaminants or ingestion of contaminated food. The CAP-93 model was used to estimate multipathway exposures and risks due to radionuclide emissions to humans within 50 km of all 684 utilities. However, this assessment did not use site-specific data for the non-inhalation exposure analysis, but rather relied on various generic assumptions and general input data.

Based on the CAP-93 modeling, 667 of the 684 plants are estimated to pose multipathway risks less than 1×10^{-5}. The highest estimated MEI cancer risk due to multipathway exposure to radionuclide emissions from utilities is 3×10^{-5}. Seventeen plants (13 coal- and 4 oil-fired plants) were estimated to pose multipathway risks between 1×10^{-5} and 3×10^{-5}. The estimated cancer incidence in the U.S., due to emissions and dispersion of radionuclides within 50 km of each utility, is estimated to be 0.3 cancer deaths/yr. Including consideration of long-range transport (based on extrapolation from the arsenic RELMAP results), the cancer incidence is estimated to be roughly as high as 2 cancer deaths/yr. The cancer incidence appears to be mostly due to inhalation exposure. The non-inhalation exposures contribute only slightly to the incidence. The non-inhalation exposure pathways have a greater impact on the MEIs, especially for coal-fired plants.

ES.7.3 Qualitative Multipathway Exposure Assessment

Other than radionuclides, the EPA has not assessed the non-inhalation exposures of HAPs emitted from utilities. The EPA recognizes that non-inhalation exposure pathways could be important for other HAPs (e.g., mercury, arsenic, dioxins, cadmium, lead) that are persistent and tend to bioaccumulate. As indicated above, further evaluation of mercury is planned. The other four HAPs are discussed below.

ES.7.3.1 Arsenic. Multipathway exposures potentially could increase the total arsenic risks. Inhalation cancer risks are estimated to be above 1×10^{-6} for arsenic for 4 plants (2 coal and 2 oil). Arsenic is persistent and has a tendency to bioaccumulate. Ingestion of arsenic can pose a cancer risk, and utilities emit approximately 59 tpy of arsenic nationwide. For these reasons, the EPA has initiated a multipathway assessment for arsenic.

ES.7.3.2 Dioxins. The EPA estimates that coal-fired utilities emit 0.4 pounds per year (lb/yr) of dioxin (toxic equivalents, TEQ) and that oil-fired utilities emit 0.02 lb/yr. These estimates combined are roughly 1 to 2 percent of the nationwide anthropogenic dioxin emissions. However, dioxin emissions data were only available for eight test utility plants; therefore, the emissions data for dioxins from utilities are considered more uncertain than the emissions data for many of the other HAPs.

The highest MEI inhalation cancer risk due to dioxin emissions from any utility was estimated to be 1×10^{-7}. The qualitative multipathway exposure assessment indicates that dioxins are highly persistent, tend to bioaccumulate in the food chain, are highly toxic by low-dose ingestion exposure, and present the greatest exposure through ingestion of contaminated foods. Thus, although the inhalation risks are low, the EPA believes that further evaluation of multipathway exposure for dioxins may be needed to more comprehensively evaluate the risks.

ES.7.3.3 Cadmium and Lead. Cadmium emissions from the vast majority of plants (i.e., 683 of the 684 plants) are estimated to pose inhalation risks less than 1×10^{-6}, and the highest modeled air concentration of lead was 200 times below the national ambient air quality standard (NAAQS) for lead. Yet, cadmium and lead are persistent, may bioaccumulate, and are toxic by ingestion. Therefore, the EPA may consider conducting further evaluations of multipathway exposures of cadmium and lead emissions from utilities in future analyses.

ES.7.3.4 Nickel and Chromium. Nickel and chromium were not considered to be priority for non-inhalation exposures. At relatively high oral doses, nickel and chromium do cause noncancer toxicity. However, at relatively low ingestion doses (below the toxic threshold), nickel and chromium are considered to be relatively nontoxic. Also, it is highly uncertain whether they pose a carcinogenic risk by ingestion. Therefore, these metals appear to be mainly a concern from inhalation exposure. Hence, the EPA does not plan to assess multipathway exposures for nickel and chromium for utilities.

ES.8 ALTERNATIVE CONTROL STRATEGIES

There are numerous potential alternative control technologies and strategies for HAPs. These include precombustion controls (e.g., fuel switching, coal switching, coal cleaning, coal gasification), combustion controls, post combustion controls (e.g., PM controls, SO_2 controls), and nontraditional controls (e.g., demand side management [DSM], pollution prevention, energy conservation). The degree of feasibility, costs, and effectiveness of each of these potential control technologies varies. For example, coal cleaning tends to remove at least some of all the trace metals, with lead concentrations being removed to the greatest extent (averaging approximately 55 percent removal) and mercury being removed the least (averaging approximately 21 percent). Existing PM controls tend to effectively remove the trace metals (with the exception of mercury) while FGD units remove trace metals less effectively and exhibit more variability. Fuel switching (e.g., switching from coal to natural gas) could result in substantial reductions in HAP emissions. There are few existing data that show the HAP reduction effectiveness of DSM, pollution prevention, and energy conservation. These control strategies need to be examined further for technical and economic considerations.

ES.9 OTHER ISSUES AND FINDINGS

ES.9.1 Emissions and Risks for the Year 2010

In addition to the 1990 analysis, the EPA also estimated emissions and inhalation risks for the year 2010. There are substantial data gaps and uncertainties in the projections to the year 2010. However, the approach utilized is reasonable given the limitations of data to complete such projections.

Based on EPA's assessment for this interim report, HAP emissions from coal-fired utilities are predicted to increase by 10 to 30 percent by the year 2010. However, based on EPA's analysis, the inhalation risks in 2010 for coal-fired utilities are estimated to be roughly equivalent to the 1990 inhalation risks. For oil-fired plants, emissions and inhalation risks are estimated to decrease by 30 to 50 percent by the year 2010. Multipathway risks for 2010 were not assessed. Utilization of add-on controls to comply with other provisions of the Act are not expected to significantly impact on HAP emissions due to their limited numbers and limited HAP control efficiency improvement. However, if additional actions are taken to reduce emissions of criteria pollutants and acid rain precursors (e.g., add-on controls to reduce SO_x and NO_x emissions), these actions could result in reductions in HAP emissions. Other potential (but unknown) actions (e.g., fuel switching, repowering) may have a significant impact on HAP emissions; however, these unknowns were not included in the 2010 projection.

The approach EPA utilized to estimate emissions for the year 2010 is one of several possible approaches for making such projections. Other organizations have made projections that differ from EPA's. For this interim report, the EPA did not conduct alternative approaches and did not compare its results with projections made by other organizations. However, if feasible, the EPA will consider evaluating alternative approaches and comparing the EPA's results with those from other organizations in future analyses.

ES.9.2 Peer Review

Draft versions of Chapters 1 through 10 of this report (not including the Executive Summary) and draft technical support documents were reviewed by numerous non-EPA scientists representing industry, environmental groups, academia, and other parties. The EPA held a scientific peer review meeting and also a public meeting in July 1995 to obtain comments from reviewers. In February, April, and September 1996, all sections of the draft report underwent additional review by EPA, State and local Agencies, and other Federal Agencies. The EPA has revised the report, as appropriate, based on the reviewers' comments. However, there were several comments that could not be fully addressed because of limitations in data, methods, and resources. Comments received by other Federal agencies that could not be substantially addressed are presented at the end of each Chapter. Draft versions of this report, along with all the comments received, have been submitted to the public docket (A-92-55) at the following address: U.S. EPA, Air and Radiation Docket and Information Center, mail code 6102, 401 M Street, S.W., Washington, D.C. 20460; telephone number (202) 260-7548. Materials are available for public review at the docket center or copies may be mailed (for a reasonable fee) on request by calling the above number.

ES.9.3 Industry Report

If alternative methods and assumptions were used to study the HAP emissions from utilities, the results would likely be somewhat different. To assess the impact of using alternative assumptions and methods, it is useful to compare the EPA study with a similar study completed by the EPRI.

The EPRI prepared a report, entitled "Electric Utility Trace Substances Synthesis Report," (November 1994) that paralleled the EPA's study. Many of the same emissions data were used and similar risk assessment methods were utilized. The EPRI study concluded that cancer inhalation risks are below 1×10^{-6} for all utilities, and noncancer inhalation risks are well below Federal threshold levels for all utilities. Population inhalation risks were determined by the EPRI to be insignificant (less than 0.1 cancer case/year). Case studies at four plants found that multimedia risks, including mercury, are below levels of concern. However, it should be noted that in the EPRI analysis, exposures to mercury through fish consumption were only considered for two of the four plants studied.

The EPRI risk estimates are generally similar to, but in several cases lower than, those of EPA. Differences between the two studies include: (1) EPA's use of a higher unit risk factor for arsenic; (2) EPA's assumption that nickel emissions were carcinogenic (EPRI assumed nickel was not carcinogenic); (3) EPA's evaluation of exposure beyond 50 km to all locations in the U.S. (EPRI did not attempt this analysis); (4) the EPRI radionuclide analysis was based on several model plants, while the EPA evaluated every plant in the U.S.; and (5) the EPRI assumed that chromium emissions were five percent chromium VI, while EPA assumed that 11 percent (for coal-fired plants) and 18 percent (for oil-fired plants) were chromium VI. In addition, the EPRI mercury multimedia study considered only the local impact from four plants (not worst-case) and did not include potential impacts of total nationwide utility mercury emissions and contributions to total environmental loadings.

ES.9.4 Potential Environmental Impacts Not Included in Study

There are other potential environmental issues associated with utilities not assessed in this report. First, this study did not assess the impacts of criteria pollutants (SO_2, NO_x, PM, carbon monoxide, and ozone) or acid rain precursors (SO_2 and NO_x), which are studied and regulated under other sections of the Act. Second, this study did not include an assessment of ecological impacts. Third, this study did not assess the impacts of carbon dioxide emissions. Fourth, this study did not assess the impacts resulting from mining, drilling, solid waste disposal, transmission, transportation, or other activities associated with electric power generation. These issues and potential impacts were not assessed because they were considered beyond the scope of this study as mandated by the Act.

ES.9.5 Link to Particulate Matter (PM)

Arsenic, cadmium, chromium, lead, nickel, and radionuclides are emitted primarily as PM. Consequently, these HAPs may contribute to PM emissions and PM health concerns, especially from poorly controlled coal-fired units and uncontrolled oil-fired units (roughly two-thirds of oil-fired units are uncontrolled for PM). The impacts for PM were not addressed in this study, but are being studied under Title I of the Act. However, if additional controls of PM emissions are utilized, this could result in reductions in HAP emissions.

ES.10 OVERALL SUMMARY

Based on this study, cancer risks due to inhalation exposure to HAP emissions from the large majority of utility plants are less than 1×10^{-6}. However, 2 coal-fired plants and up to 22 oil-fired plants are estimated to present inhalation cancer risks above 1×10^{-6} (primarily due to nickel, arsenic, radionuclides, chromium, and cadmium). The inhalation cancer risks due to exposure to the remaining HAPs emitted from utilities are estimated to be less than 1×10^{-6}. The EPA estimates that between 0.5 and 6 cancer cases/yr occur in the U.S. each year due to inhalation exposure to HAP emissions from utilities.

With regards to noncancer effects from inhalation exposure, the modeling assessment indicates that HAP emissions from utilities are not expected to result in any exceedances of the RfCs or similar inhalation benchmarks.

Further evaluation of the impacts of the long-range transport of HAPs and the speciation of nickel, and also the potential impacts of short-term peak emissions of certain HAPs (e.g., HCl, HF), may be needed to more comprehensively evaluate the inhalation exposures and risks.

Available information indicates that mercury emissions from utilities may contribute to the mercury levels in the environment, including the levels in freshwater fish. However, at this time, the EPA has not yet determined whether the mercury emissions from utilities are a concern for public health. The EPA plans to continue evaluating the potential exposures and potential public health concerns due to mercury emissions from utilities. In addition, the EPA plans to evaluate information on the various potential control technologies for mercury, including pollution prevention options, and the costs, technical feasibility of such measures, and resulting economic impacts. The EPA plans to issue a final Report to Congress at a later date which will include a more complete assessment of the exposures, hazards, and risks due to utility HAP emissions, and will include conclusions, as appropriate, regarding the significance of the risks and impacts to public health. In addition, the EPA plans to include in the final report a determination as to whether regulation of HAPs from utilities under section 112 is appropriate and necessary.